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Abstract

The Report is the first (of four) Deliverable to the first (of six) Work Package of ICOEUR project.

It covers two (of five) Tasks of the Work Package, namely:

- 1.1. Analysis of technical specifics of EU and Russian networks;
- 1.5. Study of EU and Russian legislature and electricity markets and their possible development in case of interconnecting both systems, for creation of realistic simulation scenarios.

Reported results will be used in Deliverables D1.2, IR1.3 and D1.4 of Work Package 1 and in Work Packages 2 to 4.

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ACRONYMS AND DEFINITIONS

AC:	Alternating Current
ACE:	Area Control Error
ADS:	Automated Dispatch System
AVC:	Automatic Voltage Control
BALTSO:	Former association of Baltic TSOs of Estonia, Latvia and Lithuania (now part of ENTSO-E)
BTB (or B2B):	Back to Back station
CECS:	Centralized Emergency Control System
CENTREL:	Former association of Central European TSOs of Czech Republic, Hungary, Poland and Slovakia
CIS:	Commonwealth of Independent States
DC:	Direct Current
EC:	European Commission
ENTSO-E:	European Network of Transmission System Operators for Electricity
ENTSO-E RG CE:	ENTSO-E Regional Group Continental Europe
EPC CIS:	Electric Power Council of the Commonwealth of Independent States
ETSO:	European Transmission System Operators
EU:	European Union
EURELECTRIC:	Union of the Electricity Industry
FACTS:	Flexible Alternating Current Transmission System
HVAC:	High Voltage Alternating Current
HVDC:	High Voltage Direct Current
IPS:	Interconnected Power System
Mtoe:	Million Tons of Oil Equivalent
NORDEL:	Former association of Nordic TSOs of Denmark, Finland, Iceland, Norway, and Sweden (now part of ENTSO-E)
PHARE:	EU programme to assist the countries of Central and Eastern Europe in their preparations for joining the EU
PMU:	Phasor Measurement Unit
PSS:	Power System Stabilizer
RAO UES:	Joint stock company “Unified Power System of Russia”
SO-CDA:	System Operator – Central Dispatch Administration (the highest level of the Russia’s UPS dispatch hierarchy)
SPS:	System Protection Scheme
TACIS:	Technical Assistance for the CIS (EU programme to promote the acceleration of CIS economical reforming)
TESIS:	Trans-European Synchronously Interconnected System
TSO:	Transmission System Operator
UCTE:	Union for the Co-ordination of Transmission of Electricity (former association of TSOs of continental Europe, now part of ENTSO-E)
UPS:	Unified Power System
VSC:	Voltage Source Converter

1 EXECUTIVE SUMMARY

This Report covers the results of ICOEUR Task 1.1 and Task 1.5.

Task 1.1. “Analysis of technical specifics of EU and Russian networks” investigates technical specifications in the EU (European Union) and Russian networks, referring to the network interconnection and further modeling of both power systems.

Key technical, organizational and legal aspects of the IPS/UPS¹ and ENTSO-E RG CE (ENTSO-E Regional Group Continental Europe, former UCTE) power systems are investigated with respect to a possible interconnection of these systems. The two synchronous areas have been developed and operated differently for some considerable length of time. Due to their independent development there exist major differences in system structure and operation philosophy of ENTSO-E RG CE and IPS/UPS.

The Western synchronous zone (i.e. ENTSO-E RG CE) is characterized by a high rigidity of the system, so generally the thermal limits of the elements are used as criteria for long term analysis and planning. The Eastern synchronous zone (i.e. IPS/UPS) contains a considerable number of long and therefore weak transmission lines. In these conditions it is necessary for the Eastern synchronous zone, first of all, to take into account stability margins in respect to active power and voltage as well as the overcurrents in the initial and normative post-fault schemes. A specific feature of the IPS/UPS synchronous zone is the extensive use of emergency control automatics, which significantly contributes to ensuring system security. Such technical solution is a feasible measure to ensure the system integrity in case of stability problems arising from the exceptional grid topology of IPS/UPS. While both systems follow the n-1 criteria, in IPS/UPS a wider range of means is used to overcome the consequences of disturbances (i.e. power imbalances, grip elements tripping or overloads, violations of voltage limits, etc.): protection, re-dispatching and automation actions comprising load and generation shedding.

The solutions of power and frequency control currently applied in the ENTSO-E RG CE and IPS/UPS differ significantly from each other. The most important difference is the organization philosophy of frequency control that is decentralized in ENTSO-E RG CE and centralized in IPS/UPS, which directly comes from the structure of these power systems. As a consequence of this, the secondary control in power systems of IPS/UPS means the control of tie line flows (with the exception of the Central region which is solely responsible for frequency control) in contrary to ENTSO-E RG CE, where secondary control always means control of ACE (area control error) on control block borders. Nevertheless, power and frequency control solutions currently applied in ENTSO-E RG CE and IPS/UPS are compatible, i.e. they do not exclude synchronous coupling of these two areas.

Synchronous coupling of the huge ENTSO-E RG CE and IPS/UPS power systems by a relatively weak interface naturally leads to large primary control flows, up to 1500 MW over the interface, what in turn requires permanent reservation of free transmission capacity of this amount out of the total transfer capacity of the interface. Apart from the interface this refers also to some internal congested areas within ENTSO-E RG CE and IPS/UPS.

In principle, the available reactive power reserve of all synchronous generators, synchronous compensators and compensation reactors in ENTSO-E RG CE and IPS/UPS power systems is

¹ IPS: Interconnected Power System; UPS: Unified Power System; ENTSO-E: European Network of Transmission System Operators for Electricity

sufficient to keep the voltages in the acceptable limits during the winter peak load and summer light load conditions. The switching of the on-load tap-changers of the transformers allows the distribution of reactive power and optimization of the voltage profile and the power losses in the power systems. However, all compensation equipments for reactive power near to the interface are to be inspected and tested in operation before starting the coupled ENTSO-E RG CE and IPS/UPS operation.

Regarding relay protections there are some differences in the concepts, but the greatest differences are to be found in the practical implementation. In UPS most of the relays are of the electromechanical (analog) type, while in extra high voltage systems a number of digital relays with improved characteristics are installed. In general, the philosophies of the protection systems on both sides of the interface area are similar. The applied protection schemes in IPS/UPS constitute effective protection systems with a complete redundancy compatible with the systems used in ENTSO-E RG CE.

Synchronous coupling between ENTSO-E RG CE and IPS/UPS is one option for interconnecting the two systems. As the implementation phase for all the required technical, operational, organisational, and legal measures and conditions is recognized as a long process, a synchronous coupling can be considered only as a long term perspective.

It has also to be noted that economical benefits that are mostly associated with the extension of power systems may be to some extent countervailed by technical drawbacks. In the first place, the unabated propagation of disturbances and their consequences through the interconnected system has to be prevented. As support to the creation of a joint, world-largest electricity market platform between ENTSO-E RG CE and IPS/UPS, in a medium term horizon the construction of HVDC (High Voltage Direct Current) links, either in their full or back-to-back (BTB) scheme, between the interface countries may be considered as an advantageous alternative solution. Ultimately, due to their technical advantages, back-to-back links may result in a more cost-effective and thus “easier to realize” perspective, also exploiting and/or refurbishing previously operating HVAC (High Voltage Alternating Current) lines across the interface between the two zones. The investments in the asynchronous (with BTB links) interconnection may be estimated as two times less than the synchronous option would require.

Task 1.5 “Study of EU and Russian Legislature and Electricity Markets and Their Possible Development in Case of Interconnecting Both Systems, for Creation of Realistic Simulation Scenarios” evaluates the impact on the IPS/UPS transmission systems associated to the perspective development of the Russian generation/transmission system in the current and future context characterized by the presence of new operators (e.g. public-private generation companies) in a more liberalised framework. The assessment of the EU markets and the impact of interconnection on them are provided by a synthesis of results and findings of existing interconnection studies.

Regulation of electric power industry in Russia and the EU has many common but also some different features. The common elements are:

- ◆ The unbundling of networks and system operators from other activities;
- ◆ the main functions of system operators;
- ◆ the rule of regulated third party access to networks.

However, these elements are applied in different ways. In general, Russian regulation can be characterized as more centralized and strict, while regulation of EU is more decentralized and

flexible, providing alternatives and exceptions even to the most important regulatory elements. Russian legislation does not specify explicitly the direct line principle, although there is no restriction for consumers to construct their own direct lines. The principle of temporary exemption from third party access, which is considered as positive in EU, is not applied in Russia at all. The share of governmental ownership in transmission and dispatching control in Russia is very high while it is not fixed in the EU at all.

Nevertheless, the different regulatory elements applied in Russian and EU electric power systems make no difficulties for the systems interconnection and the powers of the regulatory authorities are sufficient to organize and maintain the parallel work for the benefit of all participants.

General conceptions of market design in Russia and in the EU Member States are similar. The conceptions are based on:

- ◆ unbundling competitive and monopolistic businesses. Generating companies are separated from network and operating companies;
- ◆ privatization of companies in generation and supply businesses;
- ◆ independent (of the industry) regulation of natural monopolies;
- ◆ establishment of an independent System (Transmission, Distribution) Operator;
- ◆ simultaneous trade through bilateral contracts, day-ahead, balancing and capacity markets;
- ◆ promotion of competition in the generation and supply businesses.

Today's characteristics of the markets have differences. The main differences are:

- ◆ The Russian Federation has significant ownership in the infrastructural companies. The State owns the controlling block of shares of the generation company RusHydro and fully owns the Energoatom concern.
- ◆ The Russian legislation does not proclaim an open access for foreign suppliers to the national networks and end customers.
- ◆ There are no unified technical standards between Russia and EU for protective systems, automatic frequency and power flow control, and measurement systems.
- ◆ Involvement of customers in the competition in retail markets is different in Russia and in the EU Member States.

The problems to solve in the case of electric systems interconnection depend on the market integration scenario.

2 INTRODUCTION

2.1 Background

The ICOEUR project concept envisions an optimal technical interconnection of European and Russian electricity transmission networks: the scope is to allow best circumstances for secure and stable operation of the common as well as of isolated power systems, while providing reliable “highways” for energy exchange between the two energy markets. The secure operation is ensured by innovative control and monitoring systems, which include advanced monitoring and control tools, intelligent control devices and special protection functionality. The ICOEUR concept aims to realise the secure interconnection of both networks while retaining autonomies of all the participants with consideration of their individual technical and regulatory requirements.

The most important contribution of ICOEUR consists of the new criteria, methodologies and tools that clearly and quantitatively show to political, regulatory and infrastructural decision-makers the benefits and the way to efficient, secure and appropriate interconnections of large scale power systems.

The project encompasses four main Work Packages (WP) devoted to the objectives as described in Figure 2.1.

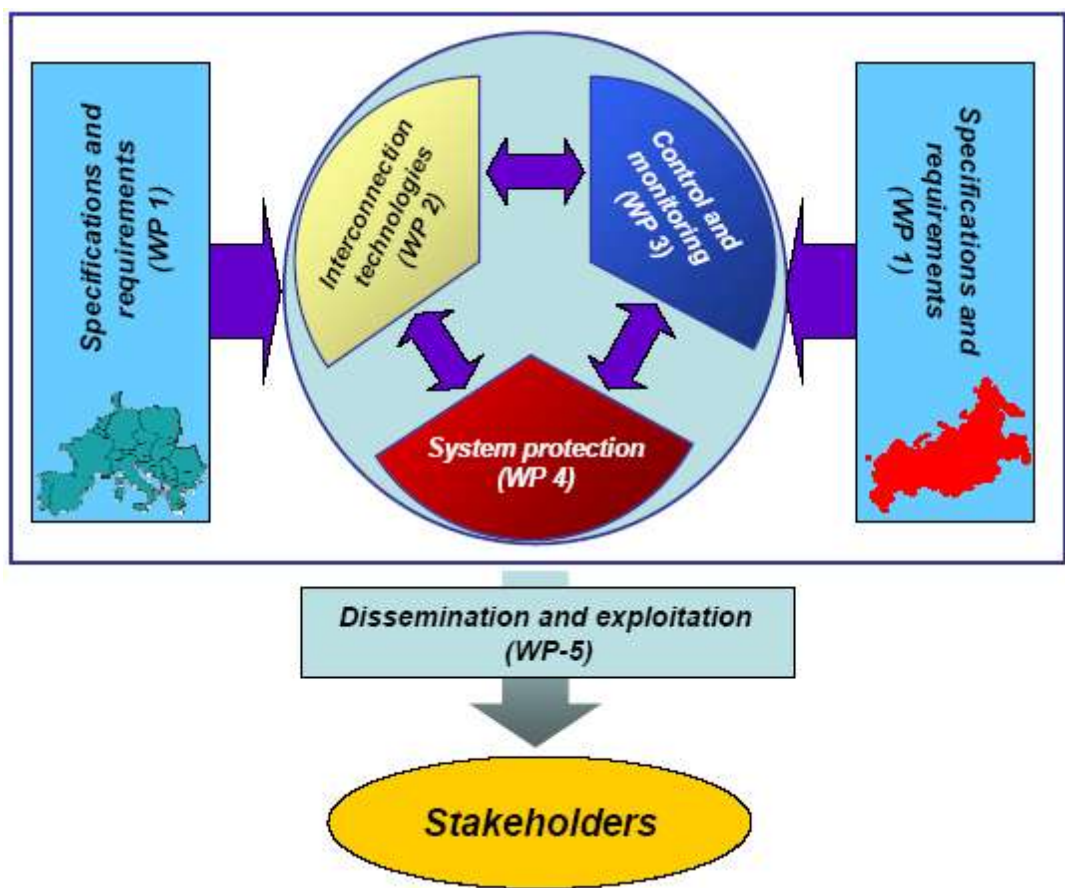


Figure 2.1: ICOEUR project structure

Work Package 1 (WP1) “Specification of requirements for extension and interconnection of large-scale power systems” identifies the needs and requirements for internal strengthening, extending and interconnecting European and Russian power systems. It focuses to direct the activities in the other Work Packages and serves as a filter for information and technology, market and commercial solutions. In this context, WP1 ensures that all technical developments start from a common framework. Realistic models of the European and Russian networks will be developed within this package, which will provide the basis for the following Work Packages. Where appropriate, existing models of the European and Russian networks will be integrated into modelling process. WP1 defines long term scenarios for the EU and Russian power sectors, characterized by different evolutions of demand and supply, such as the integration of a large amount of variable renewable energy sources (RES), to be used in next Work Packages for the creation of realistic test cases. It has to be stated clearly that the focus is both on the internal needs of the network development as well as the extensions and interconnections with surrounding systems.

The WP1 leader is Energy Systems Institute (ESI). The tasks, contributors and timing of WP1 are illustrated in Table 2.1.

Table 2.1: Tasks, contributors and timing of WP1

Task	Leader + Contributors	2009											
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
		01	02	03	04	05	06	07	08	09	10	11	12
1.1	SibEPRI + NIIPT, PoliTo, TUT	<i>Analysis of technical specifics of EU and Russian networks</i>											
1.2	ECL + ESI, TUDO, ERSE	<i>Screening and evaluation of transmission, monitoring, control and protection technologies for large scale network interconnections and grid enhancement</i>											
1.3	IPS + EPFL, PoliTo, TE, ESI, SibEPRI, BHAM, TUT	<i>Development and implementation of power system software models</i>											
1.4	BHAM + ESI, NIIPT	<i>Development of strategies for grid enhancement measures</i>											
1.5	ESI + ERSE, RTU, NIIPT, BHAM	<i>Study of EU and Russian legislature and electricity markets and their possible development in case of interconnecting both systems, for creation of realistic simulation scenarios</i>											

2.2 Objectives of this deliverable

The main objectives of this deliverable are to identify and specify the needs and requirements for extension and interconnection of large-scale power systems such as the ENTSO-E RG CE and Russian networks as basis for the following Work Packages. This can be described in a series of sub-objectives:

- ◆ Analysis of technical specifics of EU and Russian networks as well as of legislative context.
- ◆ Study of EU and Russian electricity markets and their possible development in case of the interconnection of both systems, in order to create realistic simulation scenarios.

This Report covers the results of Task 1.1 and Task 1.5 (see Table 2.1).

3 TASK 1.1. ANALYSIS OF TECHNICAL SPECIFICS OF EU AND RUSSIAN NETWORKS

3.1 Review of previous studies

The issues of cooperation between Eastern and Western Europe in the area of electricity industry have been already considered for several decades in the framework of the general energy trade (natural gas and crude oil supply from Russia as well as electricity export).

In the late 1990 – early 2000, the following activities were carried out regarding the issues of the East/West synchronous interconnection:

- ◆ **The TACIS and PHARE technical study of the interface between the extended West European power system and its Eastern neighbours** [1]. The work done was the first phase of research on the interconnection of the TESIS² and UPS power systems. The possible use of interface (220 – 400 – 750 kV links between TESIS and the UPS) was considered for the near-term energy interchange in the non-synchronous interconnection operating mode using generators in radial mode and DC (Direct Current) links as well as load islands, with due account for the permanent shutdown of the Ignalina nuclear power plant in Lithuania, and the takeover of the IPS of the Baltic States by UCTE³ accompanied by its spin-off from the UES of Russia.
- ◆ **The TACIS and PHARE technical study of the conditions for joint operation of the extended UCPTE system and power systems of Oriental Europe and Central Asia** [2]. The conditions for the interconnection of the East and West power systems were reviewed. The report demonstrates that taking into account the conditions for the UPS design, the issue of creation of the Trans-European Interconnection should be considered as organizing the joint operation of two largest interconnections of the East and West upon commonly developed terms and principles considering the mutual rich operating experience rather than the expansion of UCPTE. A detailed research and administrative program was provided.
- ◆ **TACIS-EREG 9601 programme on the East/West Synchronous Interconnection and its possibility and feasibility** [3]. The aim of this study was to assess the UPS adequacy for the synchronous interconnection with UCTE and the related requirements which guarantee the compatibility of UPS with UCTE and the security of parallel operation of UPS and UCTE. The study estimated the interface transmission capacity based on a probabilistic approach to the reliability of the modelled interconnected system (considering n-1 rule on the interface), load flow analysis and dynamic simulation. As a first result from the study review, the principles and the results of the TACIS project have to be consequently upgraded to an actual development of the power systems on both sides to the time horizon and considered market development. Pre-requisites for the possible synchronous coupling related to the IPS/UPS as well as the preliminary requirements to the IPS/UPS were defined. At the same time, no specific requirements to the control of power and frequency in the IPS/UPS were defined. Furthermore, the survey has highlighted several aspects, which have to be taken more deeply into account in future studies.
- ◆ On October 28-29, 1999, the International Seminar on Interconnection was held in Moscow under the aegis of EURELECTRIC and RAO UES of Russia, presenting the last project findings. The seminar notes in the summary [4] that the East/West synchronous

² TESIS: Trans-European Synchronously Interconnected System.

³ UCTE: Union for the Co-ordination of Transmission of Electricity (former association of TSOs of continental Europe). RAO UES: Joint stock company “Unified Power System of Russia”.

interconnection is technically feasible, however its implementation requires certain time and involves costs and therefore in the near-term only "insular" modes with AC interconnections and DC links can be used to execute individual transactions, if the electricity market so requires. It also notes that simultaneously the synchronous interconnection can be prepared on a step-by-step basis.

- ◆ **Feasibility Study – Load Flow Analysis with Respect to a Possible Synchronous Interconnection of Networks of UCTE and IPS/UPS** [5]. Since early 2000, the condition for the operation of the interconnected network has been changed in Western Europe. Driven by the EC's policy, the creation of a common open market has been started. Consequently, mainly interconnected lines, built for the system security, were loaded more and more with transit power flows. The preliminary results of the UCTE pre-feasibility load flow study [5] performed in 2002/2003 show that central European grids are already operating near the limits with the present pattern of commercial exchange between market players in the UCTE system. Consequently, any additional transit between East and West would have to be limited to values significantly lower than the physical limits of lines currently existing between the two systems. The different scenarios analyzed show that transit corridors which are more or less independent of the scenarios can be identified. The flows coming from the East along these transit corridors in the "UCTE importing" scenarios have to cross already congested borders, mainly between the CENTREL⁴ countries and Germany and Austria, and between Slovenia and Italy. The direct consequence is that in this context, the possible transits between the two systems are significantly lower than the physical capacities of the lines presently unused between East and West. Once more it has been brought to light that the synchronous interconnection between the two systems leads to the participation of the two systems to the primary frequency control. That means that in case of an outage of production in one of the systems, the other system reacts to compensate the loss of generation. The direct consequence is that this reaction creates additional flows that have to be taken into account in the transmission capacities evaluation. In other words, the Transmission Reliability Margin will increase on the already congested borders, limiting further the available capacities for transits. It goes without saying that this effect does not exist in a DC type connection.
- ◆ **Feasibility Study: Synchronous Interconnection of the Power Systems of IPS/UPS with UCTE** [6], [7]. UCTE and EPC CIS published, in December 2008, the summary of investigation and conclusion of the feasibility study [6]. The study, co-financed by DG-TREN⁵ program of the EC, was performed between April 2005 to April 2008 by a UCTE consortium of 11 TSOs⁶ and an IPS/UPS consortium of 8 companies⁷. The aim was the investigation of technical, operational, organisational and legal feasibility for a synchronous interconnection among UCTE and IPS/UPS transmission systems. Associated implementation costs and the alternative non-synchronous coupling were also investigated. The conclusions summarize the essential findings of the feasibility study, commonly agreed and shared by the study partners leaving open to stakeholders to initiate further activities. The conclusions point

⁴ Former association of Central European TSOs

⁵ Directorate-General for Transport and Energy of the European Commission (EC).

⁶ E.ON Netz GmbH (Germany), Elia (Belgium), MAVIR (Hungary), EAD (Bulgaria), PSE-Operator S.A. (Poland), Red Electrica (Spain), RTE (France), RWE (Germany), SEPS (Slovak Republic), Transelectrica (Romania), VE Transmission (Germany).

⁷ Belenergo (Belarus), Esti Energia (Estonia), KEGOG (Kazakhstan), Latvenergo (Latvia), Lietuvos Energija AB (Lithuania), Ukrenergo (Ukraine), Moldoelectrica (Moldova), Central Dispatch Organisation for the Unified Energy System RAO UES (Russia).

out that though a synchronous coupling appears technically feasible, it must be considered as a long-term option. The findings underline the overall complexity of a synchronous coupling first of all in the context of key organizational and legal aspects. The conclusions of the Study were:

1. The UCTE-IPS/UPS Feasibility Study has investigated the synchronous coupling of the IPS/UPS and UCTE power systems under consideration of key technical, organizational and legal aspects.
2. The Study brings to evidence that a synchronous coupling between UCTE and IPS/UPS is feasible upon implementing several technical, operational and organizational measures and establishing the legal framework as identified in the investigation. As the implementation phase for identified measures and conditions is recognized as a long process, a synchronous coupling should be considered as a long term perspective. In order to achieve a joint, world-largest electricity market platform between UCTE and IPS/UPS synchronous areas the construction of High Voltage Direct Current (HVDC) links between the interface countries may be considered as a medium-term alternative solution for system coupling which, however, deserves separate investigations.
3. Regarding the transfer capacities across the interface the steady state analysis shows that the potential power exchanges between UCTE and IPS/UPS are limited mainly due to internal congestions in the systems concerned. Therefore, a synchronous coupling would require investments in the transmission grids on both sides of the interface in order to maintain the transfer capacities available to the markets at present in both synchronous areas. Additional transmission system investments are necessary to ensure significant increase of power exchanges.
4. The performed dynamic stability analysis underlines the sensitivity to inter-area power oscillations of the synchronously coupled system structure. While ordinary operational disturbances are withstood by both the coupled and uncoupled systems, severe disturbances lead to wide-area oscillations in the coupled systems which could decrease system security. The necessary countermeasures require investments both in the generation and transmission sectors.
5. The Study brings to light the overall complexity of the IPS/UPS and UCTE synchronous interconnection when it comes to key organizational and legal aspects. The embedment of the resulting technical solutions for a synchronous coupling in an adequate legal and regulatory framework may only be achieved in the long term. The establishment of the legal basis for a reliable platform for synchronously coupled electricity markets which covers organizational and operational issues corresponding to EU standards would imperatively require the implementation of firm inter-zonal, bilateral and multilateral agreements to be signed by all concerned companies and their respective stakeholders.
6. The Study reveals the need for further investigations to refine and endorse the above mentioned measures and requirements. Major identified areas for further studies were specified as follows:
 - ◆ The verification of the IPS/UPS dynamic performance by longer-time observations followed by in-depth dynamic simulations on advanced dynamic models ensuring reliable simulation results.
 - ◆ The analysis of emergency situations in IPS/UPS caused by severe disturbances not yet experienced by the system - with the purpose to adapt and harmonize the currently existing operational guidelines, defence and restoration plans of both synchronous areas.

- ◆ The analysis of organizational aspects of the synchronous operation under consideration of several control blocks in IPS/UPS.

7. Decisions about further investigations are to be taken by the stakeholders concerned.

The mentioned studies were taken into consideration for Task 1.1 and the results of the Feasibility Study “Synchronous Interconnection of the IPS/UPS with the UCTE” [6], [7] were substantially used.

3.2 General characteristics of the investigated power systems

3.2.1 IPS/UPS

The Interconnected Power Systems/Unified Power Systems (IPS/UPS) is a power union presently comprising synchronously operated power systems of 14 countries: Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Mongolia, Russia, Tajikistan, Ukraine, and Uzbekistan. It is actually based on the former USSR Unified Power Systems originated in mid 50’s of the last century and being continuously developed over the last 50 years.

Synchronous operation of the power systems of the CIS countries is coordinated by the Electric Power Council of the CIS (EPC CIS). Within the framework of the EPC CIS the Commission on Operative-Technological Coordination of parallel operation of the power systems of the CIS and Baltic countries (COTC) establishes recommendatory principles of technological interaction and develops corresponding documents.

The cooperation of the Baltic power systems with the power systems of the CIS countries is performed within the framework of BRELL Committee established on the base of multilateral international agreement between TSOs of Belarus, Russia, Estonia, Latvia and Lithuania (namely, BRELL) signed in 2002.

At the moment, with 335 GW of installed capacity IPS/UPS annually supplies about 1200 TWh to more than 280 million consumers. This is the world’s most geographically extended power system, spanning over 8 time zones. Such vast territory implies certain specific features of the power system, such as:

- ◆ It comprises internally almost balanced regional power systems connected in most of the cases by congested links;
- ◆ It makes extensive use of long-distance extra high voltage transmission lines (up to 1150 kV);
- ◆ It uses automatic emergency control systems (in certain cases the n-1 criterion is only satisfied by the automatic emergency control system).

All power systems composing IPS/UPS are structurally allocated to 14 power regions (Figure 3.1):

- ◆ 6 IPS in Russia (North-West, Center, Middle Volga, South, Ural, and Siberia);
- ◆ Baltic States (Estonia, Latvia, and Lithuania);
- ◆ Ukraine and Moldova;
- ◆ Central Asia (Kirghizstan, Tajikistan, and Uzbekistan);
- ◆ 5 individual powers systems of other countries (Azerbaijan, Belarus, Georgia, Kazakhstan, Mongolia).

Each power system regulates the active power balance with or without frequency deviation correction, with or without automatic systems. The UPS of Russia controls frequency in the whole synchronous zone.

Since 2003 the Western part of Ukrainian power system, so called “Burshtyn TPP⁸ Island” has been disconnected from the rest of the system and operates synchronously with UCTE (see Figure 3.2 [8]).

The IPS of Russia North-West has a back-to-back (BTB) HVDC (High Voltage Direct Current) link with Finland. A full HVDC link between Estonia and Finland (Estlink, using VSC⁹-HVDC technology) has been in operation since December 2006. HVAC (High Voltage Alternating Current) radial operation of near generation is carried out by IPS of Russia North-West with Norway and Finland, too. Radial operation is also present between Poland and Ukraine and between Poland and Belarus. A passive island scheme is also in operation between Romania and Moldova. It has to be noted that the IPS of Russia Kaliningrad is tightly interconnected with the IPS of Baltic States. The latter are now part of the European ENTSO-E¹⁰ but are also synchronously interconnected with the IPS/UPS system.

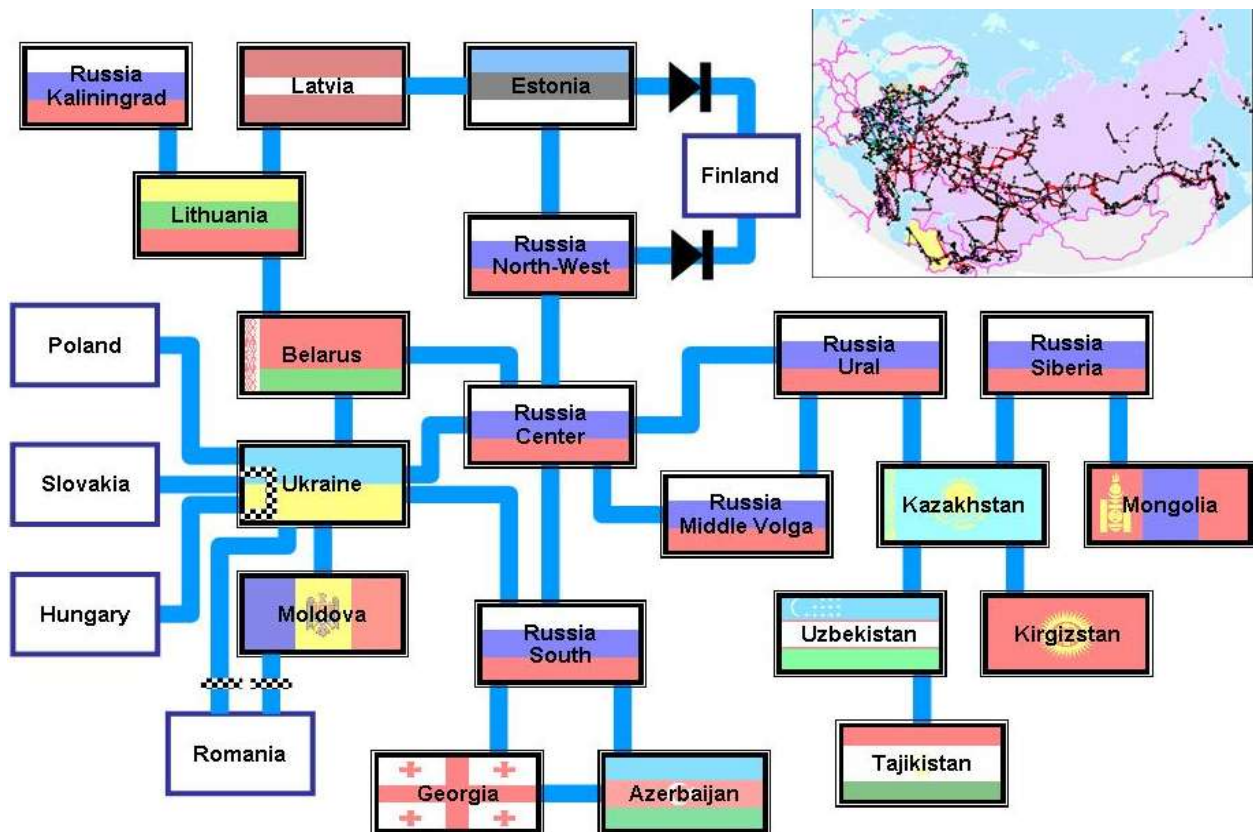


Figure 3.1: IPS/UPS synchronous zone structure

⁸ TPP: Thermal Power Plant; NPP: Nuclear Power Plant; WPP: Wind Power Plant.

⁹ VSC: Voltage Source Converter

¹⁰ ENTSO-E: European Network of Transmission System Operators for Electricity

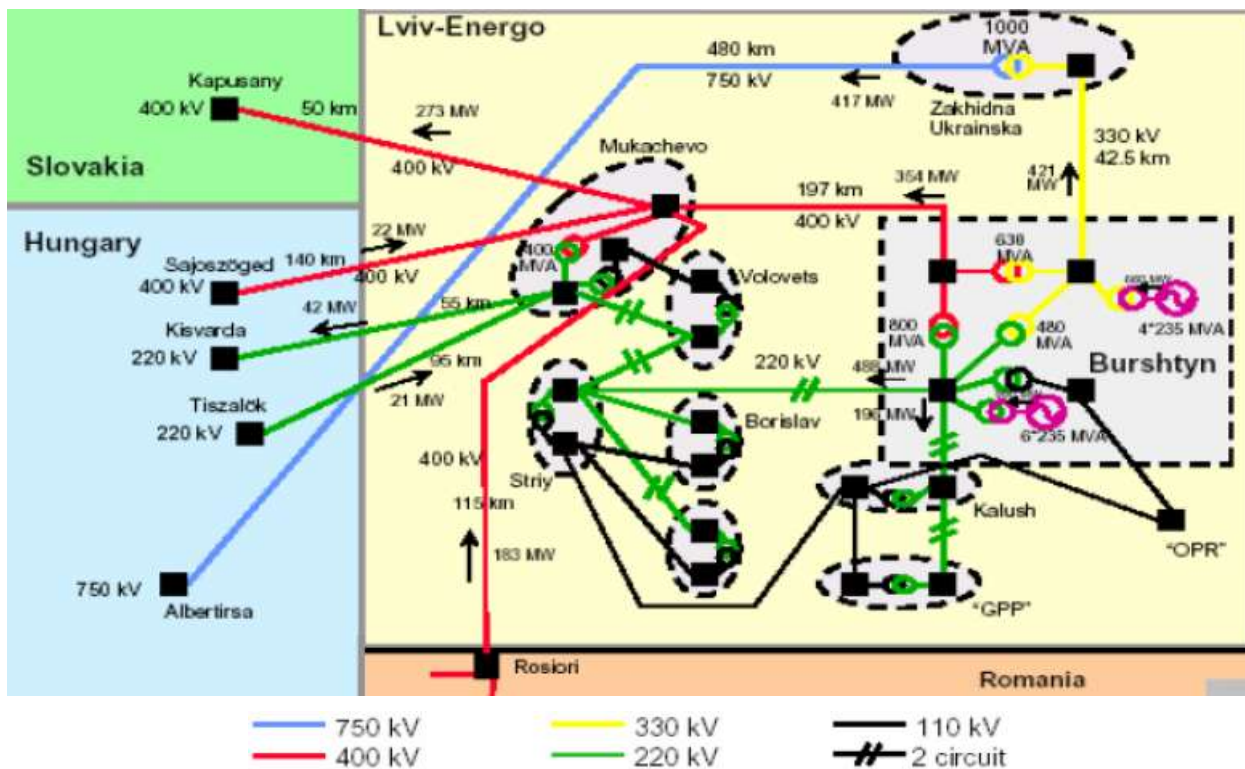


Figure 3.2: Burshtyn Island details: current state

Two scales of nominal voltages are used in the IPS/UPS: 750-330-220-110 kV and 1150-500-220-110 kV (currently, 1150 kV equipment operates at 500 kV). The backbone network of 220-1150 kV performs power transmission, while the lower voltage lines form distribution grids.

In fact, many electric ties in IPS turn out to be underloaded for a long time and their transfer capabilities are even below the limits determined by the standard margins.

The real conditions of IPS operation are illustrated by the diagrams of loading duration and level in 2000 for the intersystem ties in Figure 3.3 [9]. Each element of the diagrams represents a corresponding loading value of the ties with all higher loading values. Figure 3.3a) also shows all lower loading values – in the negative area of the flows. Thick lines show maximum admissible flows in the considered ties. The figures show that the electric ties have been operating underloaded for a long time but there are also situations where the ties are overloaded above the maximum admissible values (Figure 3.3c)).

The following technical regulations are now in force in IPS/UPS synchronous area but, however, not fully confirmed by other countries than Russia:

- ◆ IPS/UPS Intergovernmental standard 1516.3-96 “Electrical equipment for a.c. voltages from 1 to 750 kV. Requirements for dielectric strength of insulation” [10];
- ◆ Methodical Guidelines for Power System Stability of RF¹¹ Ministry of Energy [11];
- ◆ Guidelines of technical maintenance of Power Plants and Grids of Russian Federation [12];
- ◆ IPS/UPS Intergovernmental standard 14209-97 “Loading guide for oil-immersed power transformers” [13].

¹¹ RF: Russian Federation

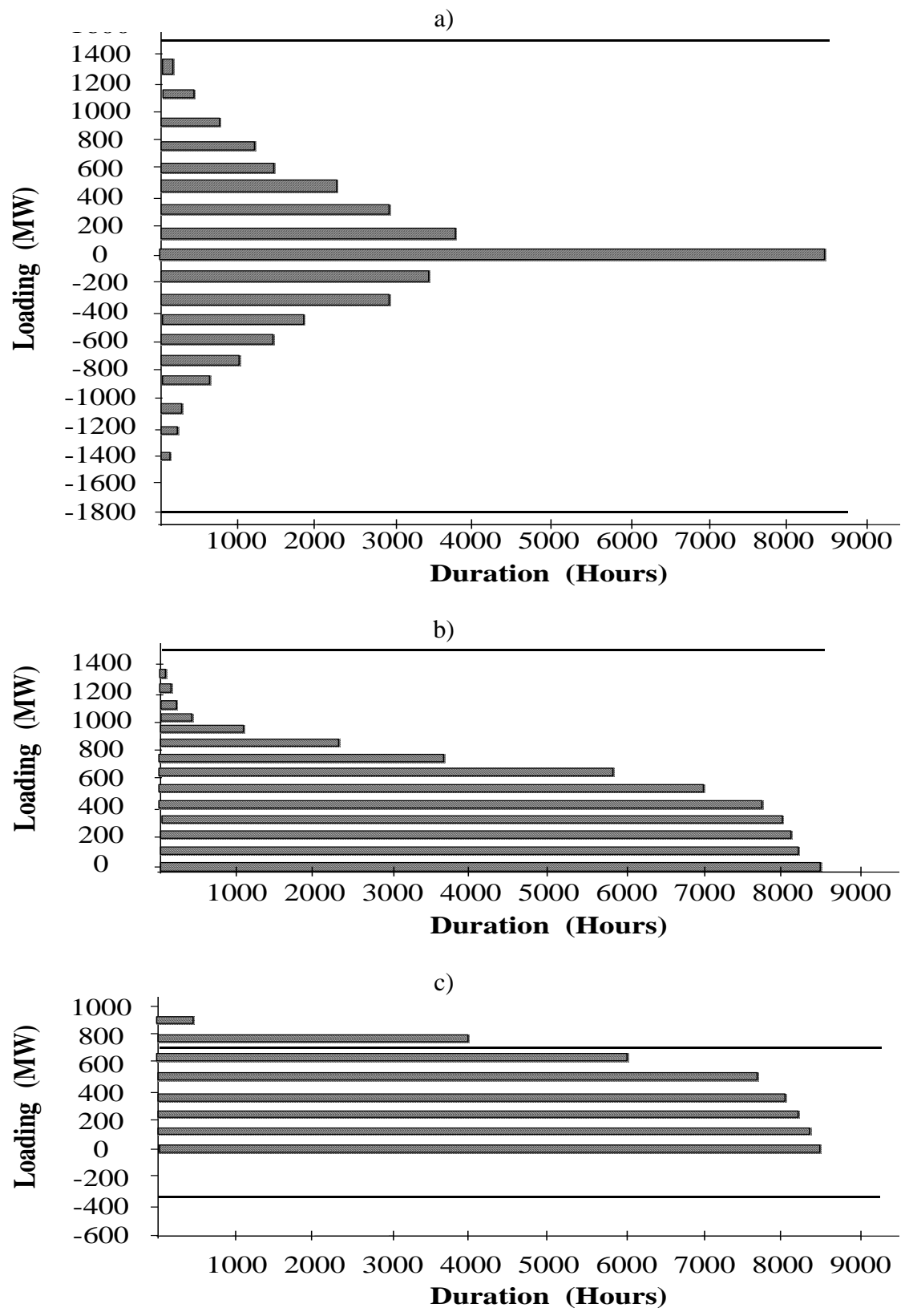


Figure 3.3: Diagrams of loading duration and level in the inter-ties:
a) "Center – North-West", b) "Center – Belarus", c) "Center – North Caucasus (South)"

3.2.2 ENTSO-E RG CE

The "European Network of Transmission System Operators for Electricity Regional Group Continental Europe" (ENTSO-E RG CE) is the association of transmission system operators in continental Europe (formerly UCTE). It aims to provide a reliable market base by coordinating the operation of electric "power highways" over the entire European mainland (Figure 3.4 [14]).

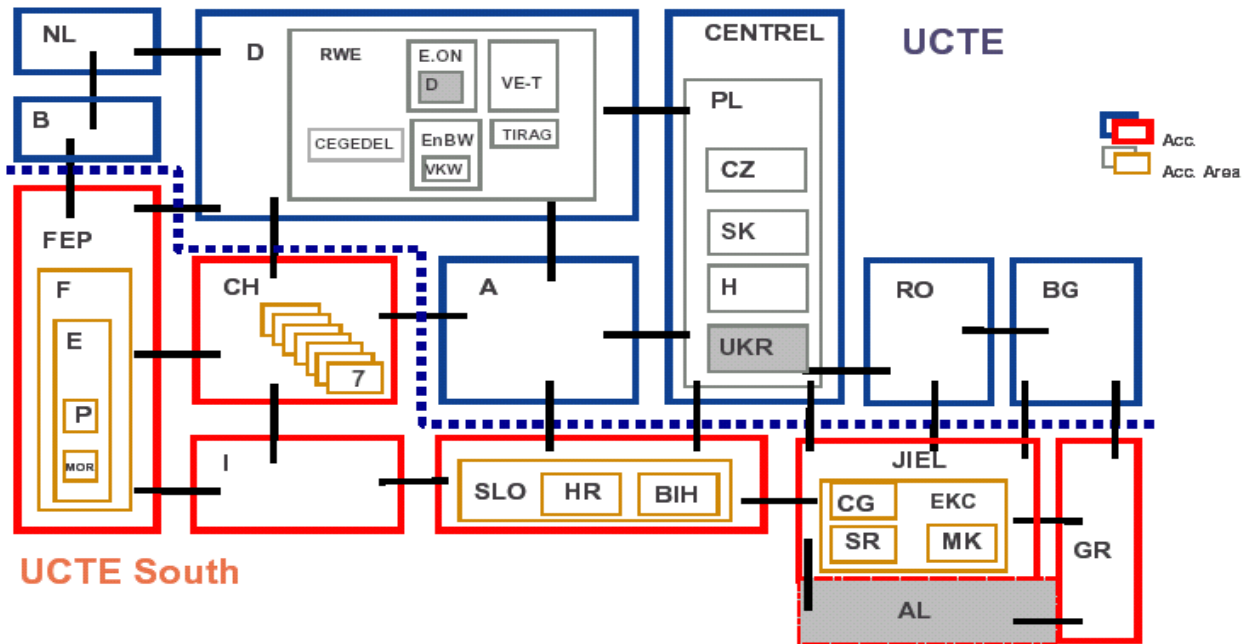


Figure 3.4: ENTSO-E RG Continental Europe (former Union for the Co-ordination of Transmission of Electricity - UCTE)

The transmission networks of the ENTSO-E RG CE members supply electricity to about 450 million people with an annual consumption of approximately 2500 TWh. The ENTSO-E RG CE system covers 23 European countries with some 220 000 km of 400 kV and 220 kV lines, thus being by far the largest interconnected system in Europe. The annual peak load in 2006 was about 390 GW. Figure 3.5 [6] gives a geographical overview about the synchronous areas in Europe, starting from the former UCTE, now ENTSO-E RG CE synchronous area. In Figure 3.5 also the other European power systems, now all part of ENTSO-E, like the former NORDEL¹² (of Nordic countries), the former UKTSOA (of United Kingdom), the former ATSOI (of Ireland), are represented with their basic features. As mentioned, also the former BALTSO (of Baltic countries) is now part of ENTSO-E, but is also synchronously interconnected with the IPS/UPS system.

Over the 2nd half of the 20th century the Continental European interconnected system was designed in order to implement principles of solidarity and economy. The former UCTE system developed then progressively into the highly meshed network that provides routes for electricity from the generation in-feed to the consumption and allows getting missing power from a neighbouring control area through the available reserves of partners. Building on the essential

¹² NORDEL: Nordic Electricity System; it is the association of the TSOs of Denmark, Finland, Iceland, Norway, and Sweden. UKTSOA: United Kingdom's TSO Association. ATSOI: Association of TSOs of Ireland. BALTSO: association of the TSOs of Estonia, Latvia and Lithuania.

principle of solidarity, the reliability, adequacy and quality of supply were continuously improved.

Today, TSOs are in charge of managing the security of the operation of their own networks in a subsidiary way based on the UCTE Operation Handbook. Individual TSOs are responsible for procedures of reliable operation in their control area from the planning period as in view of the real-time conditions, with contingency and emergency conditions. The co-ordination between TSOs contributes to enhancing the shared solidarity to cope with operational risks inherent to interconnected systems, to prevent disturbances, to provide assistance in the event of failures with a view to reducing their impact and to provide re-setting strategies and coordinated actions after a collapse.

However, the ENTSO-E RG CE interconnected system is being operated more and more at its limits. Markets trigger an increase of cross-border power flows between countries since markets by definition aim at optimizing produced power depending on short term prices differences. This leads to important variations of generation patterns within the ENTSO-E RG CE systems displacing substantial amounts of electricity from one area to another, from one hour to another, or even shorter.

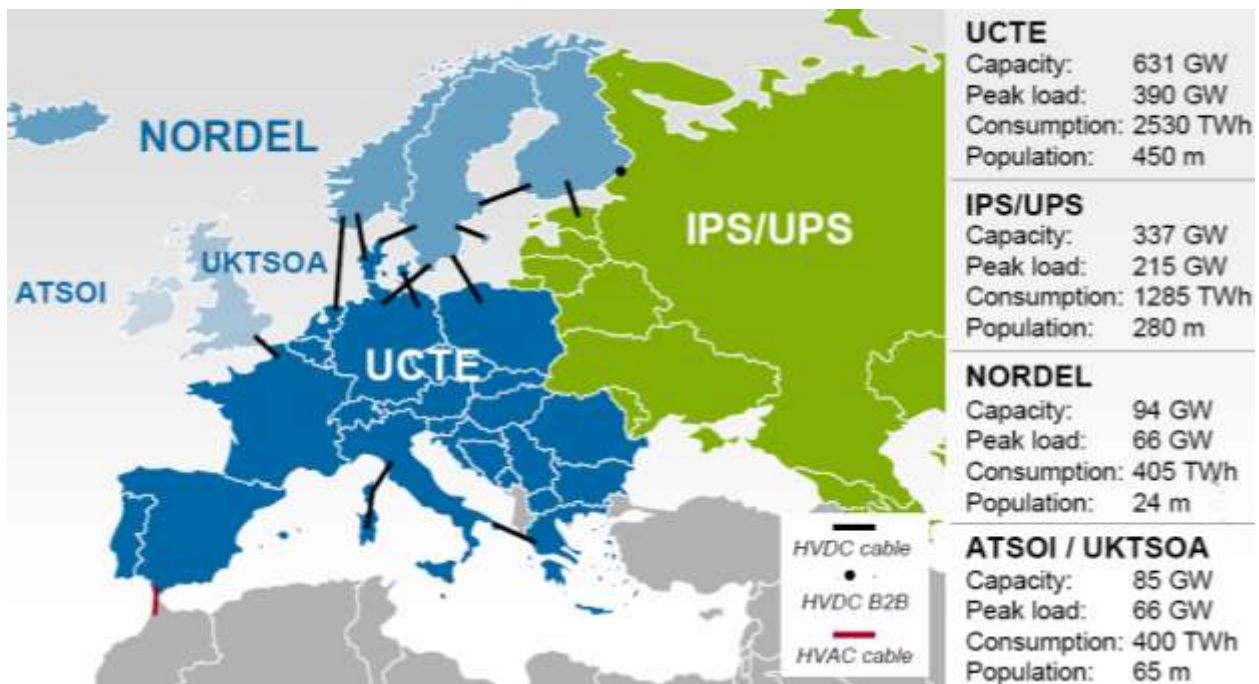


Figure 3.5: Synchronous areas in Europe (ENTSO-E)

One current example of changing generation patterns is due to the rapid development of wind generation characterized by short term predictability: within a few hours, the production of wind farms can change from minimum to maximum and conversely. This can only be mastered with an adequate transmission infrastructure and a more and more complex management of the interconnected networks. In reality, many ENTSO-E RG CE TSOs face increasing difficulties to build new network infrastructures (lines, substations, etc.). This puts more pressure than ever before on all TSOs to be able to rely on each other via closer co-ordination mechanisms as those ones stated among ENTSO-E RG CE standards.

This is why the former UCTE – supported by the European Commission and all relevant stakeholders – developed from 2002 its own “Security Package”, as a set of complementary tools:

- ◆ The *UCTE Operation Handbook (OH)* as a compendium of technical standards to be applied in the UCTE interconnected system; OH constitutes the technical/operational reference for seamless and secure operation of the power system;
- ◆ The *Multilateral Agreement (MLA)* as a cornerstone of the legal framework for the security of the UCTE interconnected systems; MLA introduces a binding contractual relation between all UCTE TSOs referring to OH.
- ◆ The *Compliance Monitoring and Enforcement Process (CMEP)* as a recurrent ex-ante process verifying the implementation of the OH standards by all TSOs as well as any measures individual TSOs have committed to towards the entire TSO community in cases of temporary non-compliance.

Even if due to national legislation and regulatory frameworks as well as due to internal procedures each TSO has to follow additional rules, the UCTE Security Package remains the basic reference for security of the interconnected system. It substantially increases transparency of the fundamentals of the TSO rules and therefore the necessary mutual confidence of TSOs among themselves as well as their credibility towards stakeholders.

3.2.3 Interface tie lines

Table 3.1 (based on [8][62]) gives an overview about the interface lines between ENTSO-E RG CE and IPS/UPS. It is worth noting that some of the lines are at moment not in operation or operated at a capacity level whose maximum is lower than the rated one (shown in Table 3.1) due to existing network constraints. Also, few additional lines (operated at 110 kV) are also present at the interface; however they cannot be retained as interconnections being only used for local electricity supply exchange [62].

Table 3.1: Transmission lines across the interface

ENTSO-E RG CE		IPS/UPS		Capacity, MVA	Voltage, kV	Status
Substation	Country	Substation	Country			
Rzeszów	Poland	Khmelnitska NPP	Ukraine	2676	750	off
Vel'ke Kapusany	Slovakia	Mukachevo	Ukraine	1186	400	on
Sajószöged	Hungary	Mukachevo	Ukraine	1390	400	on
Albertirsa	Hungary	Zakhidnoukrainska	Ukraine	4000	750	on
Kisvárdá	Hungary	Mukachevo	Ukraine	309	220	on
Tiszalök	Hungary	Mukachevo	Ukraine	309	220	on
Roşiori	Romania	Mukachevo	Ukraine	1135	400	on
Isaccea	Romania	Pivdennoukrainska NPP	Ukraine	4500	750	off
Isaccea	Romania	Vulcăneşti	Moldova	1043	400	on
Białystok	Poland	Ross	Belarus	215	220	off
Zamość	Poland	Dobrotvirska	Ukraine	309	220	on
Ełk	Poland	Alytus	Lithuania	1000	400	<planned>

The existing transmission lines in Table 3.1 were operated as an integrated part of IPS/UPS and power system “Mir” until 1995 when Poland, Hungary, Slovakia and Czech Republic were synchronously interconnected to UCTE. For a synchronous coupling of ENTSO-E RG CE and

IPS/UPS some of the lines, which are currently not in operation, will need then to be refurbished and partly reconstructed, before being again utilised. Further lines are also under study to be built across the interface between the two zones.

Due to their independent development the major differences in system structure and certain operation philosophy variations exist between ENTSO-E RG CE and IPS/UPS. While both systems follow the n-1 criteria, in IPS/UPS a wider range of means is used to overcome the consequences of disturbances (i.e. power imbalances, grid elements tripping or overloads, violations of voltage limits, etc.): protection, re-dispatching and automation actions comprising load and generation shedding.

3.3 Power System Control

3.3.1 Introduction

IPS/UPS and ENTSO-E RG CE follow similar engineering principles for dispatching and control of the active power, voltage, and reactive power. However, the control organization differs quite essentially. IPS/UPS uses a centralized control of frequency, while ENTSO-E RG CE employs a decentralized approach.

The dispatching control in the synchronous area is performed by the participating countries, each within their boundaries. In all the countries, the dispatching control is based on a centralized hierarchical framework (up to three tiers). The centralized character of control means a single entity which is in charge of reliability (integrity and balance) of the national power system operation entitled to give commands to other entities.

Another feature of the IPS/UPS synchronous area is the wide use of control automatics which brings in a substantial contribution to providing a reliability of the power system. Use of such a technical solution is expedient to provide integrity of the system in case it lacks stability caused by a non-typical topology of the IPS/UPS network.

Currently, the national power systems of IPS/UPS are employing similar control principles, however, no common reconciled operation rules have yet been elaborated.

Power system control analysis embraces the following issues:

- ◆ frequency and power control;
- ◆ control of voltage and reactive power;
- ◆ protection system at interface line;
- ◆ elaboration of Defence plan of an interface area.

3.3.2 Power & frequency control

3.3.2.1 Introduction

The most important issue to be coordinated in a synchronous area is the one of frequency control. If generation and demand are not matched, the system frequency increases or decreases. Since electricity can hardly be stored in sufficient quantities, in the isolated power system the amount of generated power must precisely follow the demand. This requires maintaining of adequate generation power reserves for control purposes and operating of control mechanisms in different time scales (commonly known as power balancing, including the task of frequency control).

In a synchronously interconnected power system with two or more independently controlled areas, in addition to control of frequency, the generation within each area has to be controlled so as to maintain scheduled power exchange between the areas. The control of generation and frequency is commonly referred to as power and frequency control and has to be coordinated and even standardized to some extent within the synchronous area. Obviously, the larger the area the more complex is this coordination. The synchronous interconnection of power systems provides the possibility for mutual help in compensating imbalances but on the other hand leads also to the occurrence of long distance regulating power flows over the whole synchronous area for which relevant transmission capacities should be reserved. And again, the larger the synchronous area the more influence of long distance regulating power flows takes place. The tight power and frequency control is also a precondition for proper operation of electricity markets (accountability in power exchange). Usually, this task is performed by Transmission System Operators (TSOs) those have to ensure the relevant amount of power reserves for control purposes. Additionally, for timing purposes, it is also desirable to maintain the synchronous time, i.e. the integral of frequency.

3.3.2.2 Power and frequency control in ENTSO-E RG CE

The philosophy of power and frequency control in ENTSO-E RG CE is decentralized among all its members. The basic element of ENTSO-E RG CE system is a control area, which is defined as a smallest portion of a system equipped and operated with load frequency controller and being physically demarcated by the points of measurements of the power exchange. The TSO of a given control area is responsible for primary control within its territory and shall have also the ability to maintain power exchange with neighbouring control areas as scheduled. What is very important in ENTSO-E RG CE approach each control area shall maintain, even in case of major frequency deviations, its interconnections with adjoining areas provided that the secure operation of its own system is not jeopardized. One or more control areas working together in the secondary control function with respect to the rest of synchronous area constitute control block. The organization of a secondary control within a control block varies across the ENTSO-E RG CE system and can be centralized, pluralistic or hierarchical. The leading TSO of a given control block shall have the ability to maintain the total power exchange schedule of the block towards all other control blocks. Figure 3.6 shows the current organization of power and frequency control within ENTSO-E RG CE system.

Primary control. In case of active power imbalance with corresponding frequency deviation, the primary control is automatically and simultaneously activated at all generating units involved across the whole ENTSO-E RG CE system and transmitted towards the place of imbalance. Primary control involves the action of turbine speed governors in generating units, which respond when the frequency deviates from its set point, since the frequency is a measure for the speed of generators. The range of insensitivity of turbine speed governors should be as small as possible, not larger than ± 10 mHz while the dead band is set in the range of ± 20 mHz. The maximum instantaneous deviation between generation and demand (the reference incident) to be corrected by primary control amounts to 3000 MW. This means that the overall primary control reserve within ENTSO-E RG CE shall be not less than 3000 MW. As a result of the shortfall in capacity equal to reference incident quasi-steady-state frequency deviation must not exceed 200 mHz. Thus the overall network power frequency characteristics λ for the whole system is determined at least at 18 500 MW/Hz including 1% of load effect, i.e. 3500 MW/Hz. This is the designed value, in practice this value for the current operating conditions of ENTSO-E

RG CE synchronous area varies between 20 000 MW/Hz and 25 000 MW/Hz (practical value). Each control area contributes to primary control in proportion to its share in the last year electricity generation to assure its homogeneous distribution within the synchronous area. The droop and characteristics of generating units involved in control must be such, that the primary control reserve must be fully activated within 15 seconds in response to disturbances less than 1500 MW, or within a linear time limit of 15 – 30 seconds in response to a disturbance of 1500 – 3000 MW.

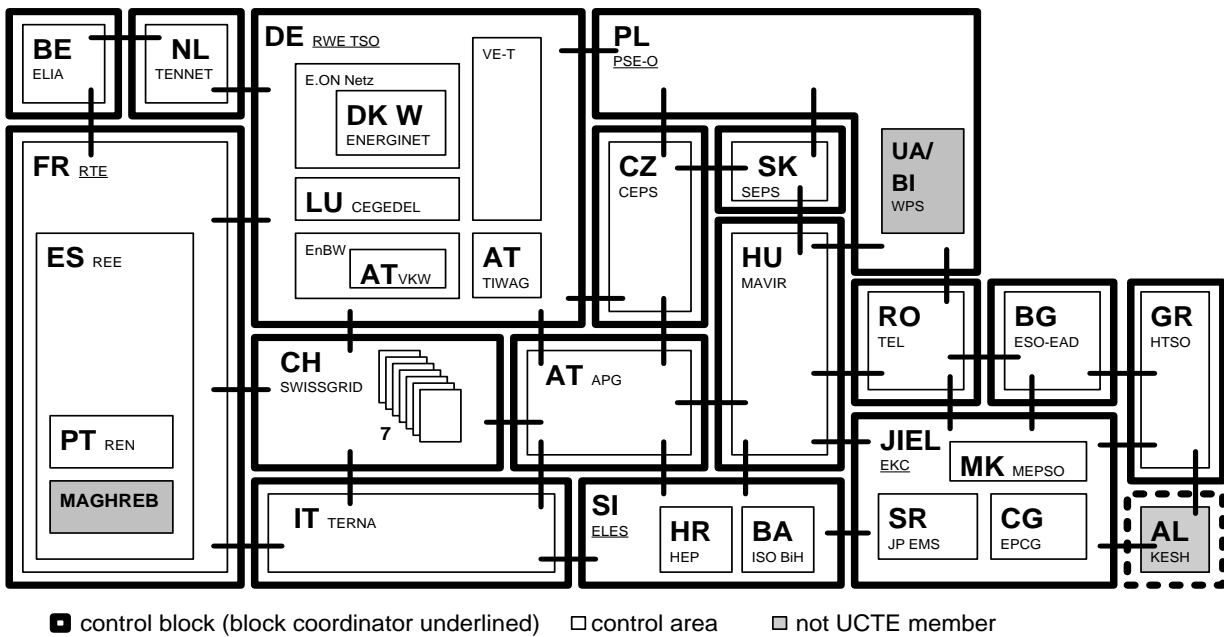


Figure 3.6: Current organization of power and frequency control within ENTSO-E RG CE system

Secondary control. Within the framework of primary control the power output of the generators is adjusted until a balance is reestablished between power generation and consumption. In this manner the frequency is stabilized at a quasi-steady-state value, which differs from the set point. To restore the frequency to its set point value and power exchanges between control areas (control blocks) to the scheduled values the secondary control is automatically activated, but only in power plants of the control areas where the imbalance occurred (according to the so called non intervention rule). These actions of secondary control on generated power and frequency take place either in response to minor deviations, that inevitably occur in the course of normal operation, or in response to a major discrepancy between generation and demand associated with for example the tripping of a generating unit. They are activated in control areas, where area control errors (ACE), calculated as below, differs from zero:

$$ACE = \Delta P + K_r \cdot \Delta f,$$

where: ΔP – deviation of real power exchange from the scheduled one, K_r – parameter applied to given load frequency controller, Δf – instantaneous frequency deviation from the set point value. In order to ensure that secondary control is only called up in control area, that is the source of disturbance the value of parameter K_r for a given control area should be as close as possible to its network power frequency characteristics λ (it is

assumed as $1.1 \cdot \lambda$). Secondary control must begin within 30 seconds of the disturbance concerned, i.e. when the action of primary control is complete and must be fully activated within 15 minutes. To be able to fulfil the above requirements the following minimum volume of secondary control reserve S is recommended in a given area with the maximum anticipated load L_{\max} [MW]:

$$S = \sqrt{a \cdot L_{\max} + b^2} - b ,$$

where: $a = 10$ MW and $b = 150$ MW. This gives, for example secondary control reserve of 300 MW and 700 MW for a system with 20 GW and 70 GW of maximum load respectively, which is supposed to compensate load noise effect and deviations of real load from forecasted one. If the loss of the largest generating unit supplying the area concerned is not covered by the secondary control reserve calculated as above, provision must be made for additional reserve, so called tertiary control reserve (sometimes referred as a minute reserve) to offset the shortfall within required time. Apart from providing an adequate amount of secondary control reserve the main task of activating tertiary power reserve is to redistribute secondary power reserve according to economic criteria. This reserve may take the form of generating plant with the facility for rapid start up, the adjustment of set points for generating units in service and can be activated automatically or manually.

Time control. The discrepancy between synchronous time (integral of frequency) and universal coordinated time must not exceed ± 30 s. In case it approaches that limit the correction procedure is applied by setting of the set point frequency for secondary control in each area at 49.99 Hz or 50.01 Hz during the whole day (24 h).

3.3.2.3 Power and frequency control in IPS/UPS

IPS/UPS system is illustrated in Figure 3.7 as major power blocks connected by relatively weak tie lines. This block model is very good for illustrating the power and frequency control of IPS/UPS. In the contrary to ENTSO-E RG CE power systems with relatively evenly distributed power generation and consumption, the IPS/UPS power systems consists of regions with substantial under and overcapacity as many large coal and hydro power plants have been built close to fuel supplies rather than load centres. The large consumption regions are interconnected with remote surplus capacity regions by means of extra high voltage (500 kV, 750 kV and even 1150 kV) transmission lines.

While describing the current situation in IPS/UPS one has to have in mind significant changes that have taken place in the power industry of Commonwealth of Independent States since beginning of nineties, when the former "Mir" power system was split into several parts, some of which, namely CENTREL (Czech Republic, Hungary, Poland and Slovakia) and later Romania and Bulgaria were connected to UCPT. These changes have had great impact also on power and frequency control solutions resulting in radical improvement of frequency quality in IPS/UPS during the latest years.

The philosophy of frequency control within IPS/UPS is quite different than in ENTSO-E RG CE since it has been always centralized. The UPS of Russia (and more specifically the dispatching centre of Central block in Moscow) maintains frequency of whole IPS/UPS, while all other control areas and blocks within IPS/UPS (shown in Figure 3.7) perform the frequency-biased tie-line power control. This kind of control is realized automatically in the Ukraine and Moldova

control block and in Siberia control area; in the remaining control areas and control blocks the controls are realized manually by dispatchers. Also in IPS of North Caucasus, IPS of the Urals, IPS of Centre and in IPS of Siberia the automatic power flow limitations (PFL) on indicated cross sections are performed.

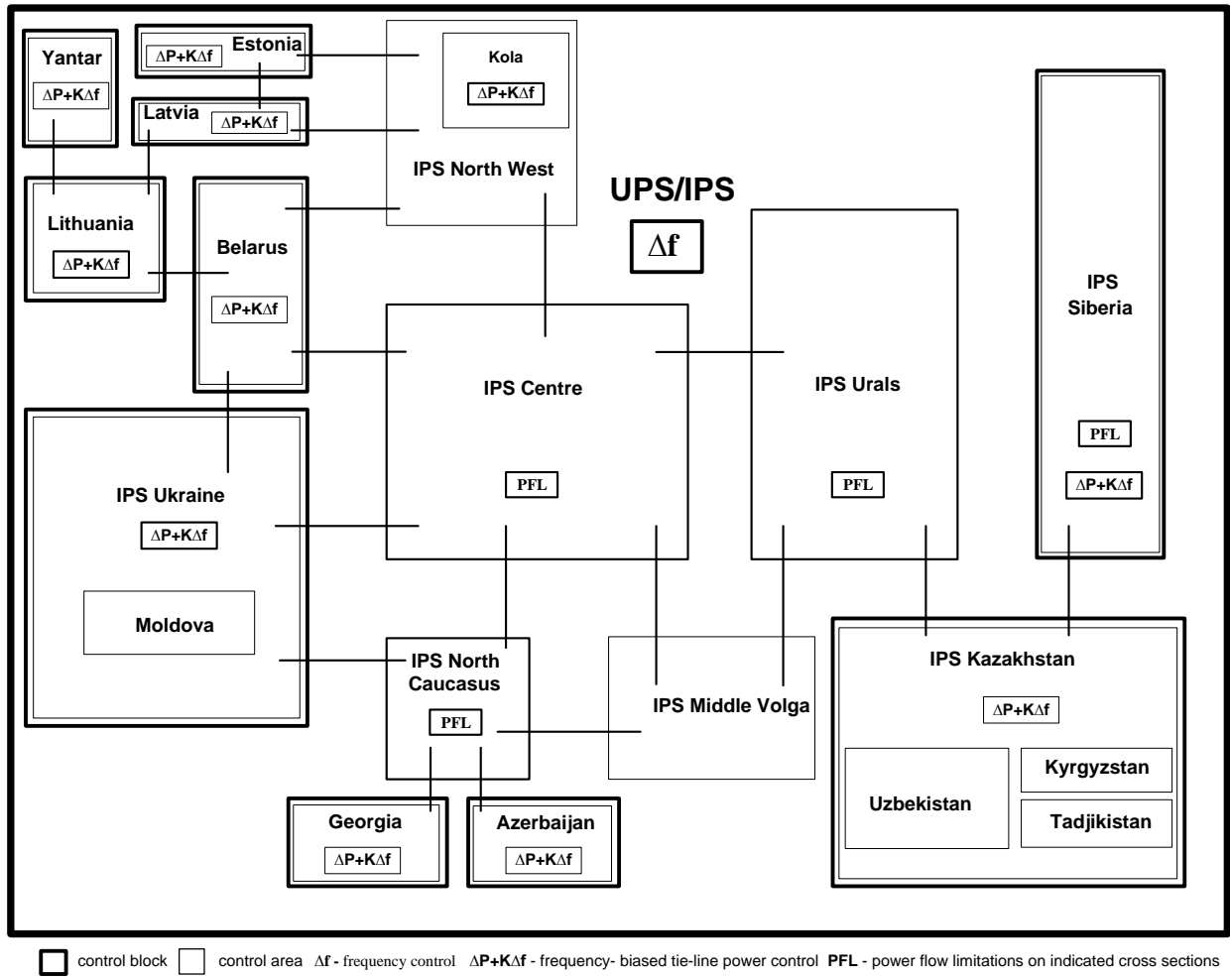


Figure 3.7: Current organization of power and frequency control within IPS/UPS system

Primary control. Today majority of the power plants participate or are going to participate in the primary control, which shall balance power imbalances up to the reference incident – the loss of a 1200 MW unit in thermal power plant or load tripping (1200 MW). During normal stationary operating conditions the deviation of frequency from 50 Hz does not exceed 50 mHz (20 mHz in ENTSO-E RG CE). At present primary control in IPS/UPS is performed by majority of the power plants in a range of their possibilities with adjustment of primary controllers that are necessary for generator reaction on emergency frequency deviations (stationary deviation more than 0.2 Hz). At the frequency deviations that are specific for the normal operation conditions of IPS/UPS (within 0.2 Hz) generator reaction is of a random character and thus the overall network power frequency characteristics λ for the whole system is unstable (changes from 10000 up to 30000 MW/Hz). The averaged value of these characteristics λ determined at the cases of generation losses is equal to 22700 MW/Hz. A number of thermal power units have been

currently modernized to participate in normative primary control and to stabilize overall network power frequency characteristics λ . These thermal power units activate a primary reserve within 30 second at frequency deviations up to 200 mHz. At present 35 thermal power units with total capacity of 14000 MW have been already modernized that allows having ± 700 MW of primary reserve. It is planned to increase the total capacity of modernized thermal power units up to 32000 MW (10% of IPS/UPS total capacity).

Secondary control. As already mentioned above, the secondary control within UPS/IPS is centralized, as shown in Figure 3.7. The central secondary controller located in Moscow (Central region) controls the frequency, while the other secondary controllers control frequency-biased tie-line power and limit power flow on indicated cross sections. The automatic secondary control reserve in UPS/IPS is maintained in a selected hydro and thermal power plants: Zhigulevskaya hydro plant for frequency control, 1 Dneprovskaya, Sayano-Shushenskaya and Bratskaya hydro plants for frequency-biased tie-line power control, Chirkeysкая, Kamskaya and Votkinskaya hydro and Permskaya thermal plants for power flow limitation,. The manual tertiary reserve, that shall re-establish the necessary volume of the secondary reserve, following the disturbance, is maintained in selected power plants dedicated to this purpose (hydro, pumped storage, and thermal).

Time control. Dispatch center in Moscow controls time correction. Normal range of discrepancy between synchronous time and universal coordinated time (time error) must not exceed ± 20 s, while maximum range must not exceed ± 30 s (as in ENTSO-E RG CE). If at 8 a.m. every day the time error does not exceed the maximum range time correction does not perform. Otherwise the controller of synchronous time sends commands to all dispatch centers of UPS/IPS to change the set value of frequency for ± 0.01 Hz for the whole day (24 h).

3.3.2.4 Conclusions

The solutions of power and frequency control currently applied in the ENTSO-E RG CE and IPS/UPS differ significantly from each other. The most important difference consists in organization philosophy of frequency control that is decentralized in ENTSO-E RG CE and centralized in IPS/UPS, which directly comes from the structure of these power systems. As a consequence of this the secondary control in power systems of IPS/UPS means the control of tie line flows (except the Central region which is solely responsible for frequency control) in contrary to ENTSO-E RG CE, where secondary control always means control of ACE on control block borders.

Nevertheless power and frequency control solutions currently applied in ENTSO-E RG CE and IPS/UPS are compatible i.e. they do not exclude synchronous coupling of this two areas.

The changes in the whole economy of CIS entailed the process of revising the power system control regulations. In turn it led to significant improvements of quality of power and frequency control. Currently this quality level in IPS/UPS is comparable with ENTSO-E RG CE.

Synchronous coupling of the huge ENTSO-E RG CE and IPS/UPS power systems by relatively weak interface naturally leads to large primary control flows over the interface, what in turn requires permanent reservation of free transmission capacity of this amount out of interface total transfer capacity. Apart from the interface this refers also to some internal congested cross sections within ENTSO-E RG CE and IPS/UPS.

3.3.3 Current state of voltage and reactive power control at the interface between IPS/UPS and ENTSO-E RG CE

The interface between IPS/UPS and ENTSO-E RG CE consists of the overhead lines presented in Table 3.1.

All network transformers in the interface area can be switched to control the voltage on the low voltage side manually, and using remote control. The positions of the transformer taps are transmitted to the national and regional dispatching centers. Table 3.2 presents compensation reactors installed near the interface. All of them are being switched as a whole. No capacitors, synchronous and static compensators are installed near the interface.

Table 3.2: Compensation reactors across the interface

Country	Substation	Voltage, kV	Number × Capacity, Mvar
Ukraine	Zahidnoukrainska substation	750	7 x 300
	Pivdennoukrainska NPP	750	3 x 300
	Khmelnitski NPP	750	3 x 300
Poland	Rzeszów substation	750	2 x 300
Hungary	Albertirsa substation	750	2 x 300
Slovakia	Veľke Kapusany	400	150
Romania	Isaccea substation	750	300
	Roșiori substation	400	100

All power plants participate in the production of reactive power. All power plants have the possibility of reactive power control in the generating nodes and can be instructed by dispatchers to do so according to their technical limits. The minimum and maximum standardized voltages on bus bars in ENTSO-E RG CE and IPS/UPS are presented in Table 3.2.

Table 3.3: Minimum and maximum standardized voltages (V_{\min} - V_{\max} , kV)

Nominal Voltage, kV	Ukraine	Poland	Slovakia	Hungary	Romania
750	712 - 787	710 - 787		697 - 787	735 - 765
400	380 - 420	380 - 420	390 - 420	380 - 420	380 - 420
220	187 - 253	210 - 245	198 - 242	189 - 244	198 - 242
110	99 - 121	105 - 123	99 - 121	108 - 138	99 - 121

In principle, the available reactive power reserve of all synchronous generators, synchronous compensators and compensation reactors in ENTSO-E RG CE and IPS/UPS power systems is sufficient to keep the voltages in the acceptable limits during the winter peak load and summer light load conditions. The switching of the on-load tap-changers of the transformers allows the distribution of reactive power and optimization of the voltage profile and the power losses in the power systems. However, all compensation equipments for reactive power near to the interface are to be inspected and tested in operation before starting the coupled ENTSO-E RG CE and IPS/UPS operation.

3.4 Emergency control in Russia

3.4.1 Control centres and principles of real-time dispatch – 1st line of defence

3.4.1.1 Principles of operation of the grid control centres

The main principles of the Russian hierarchical dispatch system are as follows [15]:

- ◆ Separation and independence from the administrative and economic management functions.
- ◆ Hierarchical structure with the direct subordination of the lower-level dispatchers to the higher-level dispatchers.
- ◆ Independence of the dispatchers at each level when intervention from the high-level dispatchers is not needed.
- ◆ Clear definition of the dispatch personnel responsibilities at each level at normal and emergency conditions.
- ◆ Strictest dispatch discipline.

The basis of the Russian dispatch system is formed by the centralized Automated Dispatch System (ADS). The ADS structure is shown in Figure 3.8 [15].

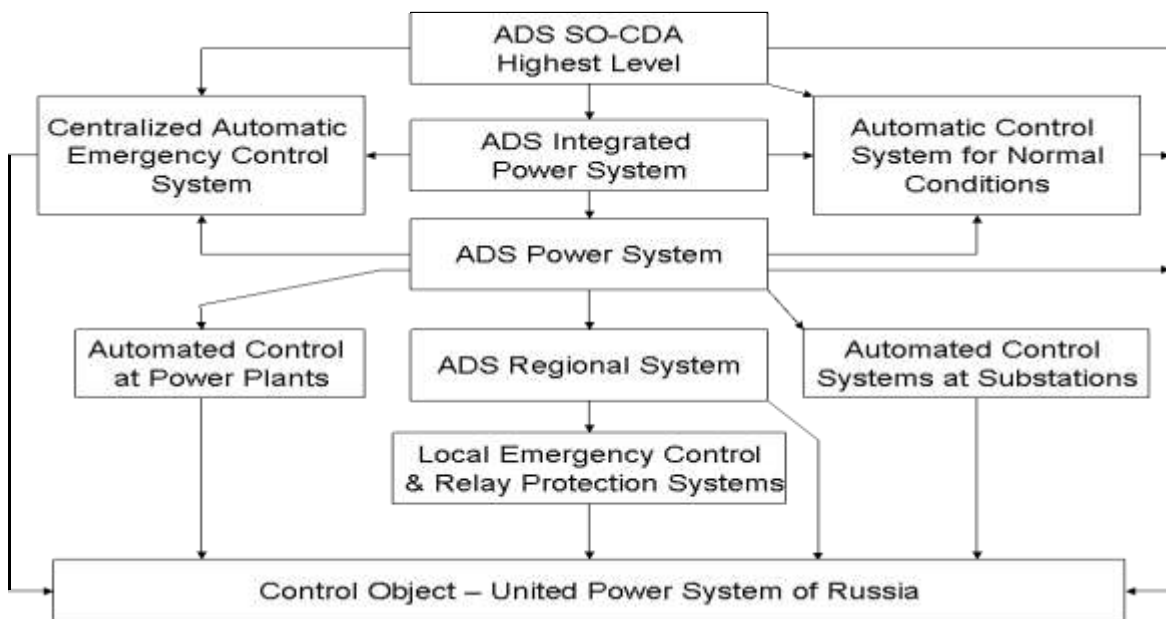


Figure 3.8: Russian centralized automated dispatch system

3.4.1.2 Hierarchical state estimation – "Wide area" approach

One of the main reasons of the US-Canada blackout on August 14th, 2003, was the lack of "wide area" visibility of the system state and processes in the neighboring Control Areas [16], [17]. Availability of the actual power flow model provided by the state estimation algorithms is considered in Russia as a necessary condition for the adequate decision-making by real-time dispatchers. Periodic state estimation is conducted automatically and simultaneously on the upper and lower levels of the dispatch control hierarchy. The lower level results are sent to the upper levels where they are processed and combined together to form a wider-area state estimation model. State estimation results are presented on the "visual walls". Visual walls form

a friendly interface to the dispatchers where the state estimation results form a comprehensive, easy-to-understand, changing image that helps a the real-time dispatcher to quickly apprehend and understand the situation.

3.4.1.3 Interconnection frequency control

Significant and/or sustained deviations of the interconnection frequency can cause the under- or over-frequency relaying and force some loads and generators to trip. Under unfavorable conditions, this may result in a cascading failure and system collapse that is pictorially called in Russia “an avalanche of frequency”. Under the steady-state conditions, frequency is a uniform parameter in an AC interconnection, and it appears to be logical and most efficient to control it from one designated center.

Frequency control in Russia is based on the centralized frequency control plus manual operating procedures plus coordinated automatic actions plus under- and over-frequency relaying plus mandatory reliability requirements. The Russian frequency standards limit frequency deviations at normal operating conditions by ± 0.1 Hz. Short-term deviations are limited by ± 0.2 Hz [18]. Manual Operating Procedures [15], [16], [19]:

- ◆ *Sudden Frequency Decrease by 0.1-0.2 Hz.* The SO-CDA dispatchers determine the reasons of the decrease and issue mandatory instructions to the dispatchers of the IPS to increase generation by using a specified amount of the spinning reserves. The instructions must not cause violations of the operational transfer capability on the inter-ties connecting regional systems.
- ◆ *Subsequent Frequency Reduction by 0.5 Hz and Lower.* The SO-CDA and IPS dispatchers issue mandatory instructions to the plants to fully engage their spinning reserves and to start up non-spinning hydro generators, to move the units operating in the synchronous condenser mode to the generation regime, and to increase generation on the thermal power plants. All transmission constraints must be satisfied.
- ◆ *Further Frequency Reduction Regardless Under-Frequency Relays Actions; Frequency Decrease Remains 1 Hz or Lower for 3-5 Minutes.* The SO-CDA and lower level dispatchers issue mandatory instructions to curtail the load; this must not cause transmission violations. Lower level dispatchers obey SO-CDA instructions, but they also make their own decisions; if their area is separated from the system or frequency reduction reaches 1.5 Hz, they act completely independently shedding the load (after 3-5 minute delay needed to engage all generation available reserves).

Similar procedures are developed to cope with the frequency increases. Frequency excursions of such a magnitude can only happen when some parts of UPS separate from the rest of the grid with significant load/supply imbalances inside them. Nevertheless, the corresponding procedures are enforced, and the dispatch personnel is trained to follow them.

3.4.1.4 Other emergency dispatch procedures in Russia [15]

The system failure development process is usually too fast to allow real-time dispatchers to intervene. The power grid under these conditions is controlled by the emergency control systems and relay protection schemes. In most cases, the real time dispatchers start to act at the post-fault stages. Their task is to restore power supply of interrupted loads and to return the operating conditions to normality as quickly as possible. The emergency dispatcher control is performed by coordinated actions of real-time dispatchers at different levels of the dispatch hierarchy. The main condition of a successful emergency control is considered to be an optimal separation and

definition of the higher and lower level dispatch functions. The core idea is to provide maximum degree of independence of the lower-level dispatchers addressing their regional emergency situations. The upper level dispatchers intervene only when the problem becomes their level problem. Thus, the SO-SDA dispatchers lead the emergency control in situations where the problem becomes system wide, such as faults on the inter-ties connecting IPS, system separation, frequency reduction, etc. The entire process is instructed by very clear operating procedures. These procedures address deep reductions of the frequency and voltages, sudden reductions of the frequency and voltages, overloads on the transmission lines, asynchronous operation, system separation, etc.

3.4.1.5 System restoration procedures

The restoration process in Russia is led by a higher-level dispatcher in the dispatch hierarchy. The procedure includes the following steps [15], [20]:

1. *Recovery of the Generation Capacity.* The first priority of the dispatchers is to prevent damages or long-term capacity loss on the ST (Steam Turbine) units and nuclear plants that remain operational under the no load condition. The recovery process begins with starting the hydro and CT (Combustion Turbine) units. The supply from these units is then used to feed auxiliary loads and start non-spinning STs. As a black-start measure, at the dangerous excursions of the system frequency or voltage, some generators are separated from the grid and are kept spinning to use them later in the restoration process.
2. *Resuming Normal Operations on Substations.* The key concern is maintaining a sufficient air pressure to provide conditions for closing air breakers. Another important concern is preventing dangerous voltage surges and frequency declines. Before connecting lines with large capacitance it is prescribed for substations of lower voltage:
 - ◆ to connect additional loads on intermediate substations of long-distance transmission lines;
 - ◆ to deactivate temporarily automatic protection devices such as automatic re-closing of circuit breakers, under-frequency relays, OLTCs (On Load Tap Changers), etc.

Manual restoration of system loads during a frequency recovering process is allowed by permission of the SO-CDA dispatcher to prevent secondary frequency declines.

3.4.2 Automatic centralized emergency control systems – 2nd line of defence

The main use of the centralized emergency control systems (CECS) is providing system stability [21]. These systems collect and process information regarding the current state in a large power system region or in the entire power system. The remedial actions may include a variety of geographically dispersed measures triggered by sophisticated algorithms. The algorithms perform the following functions:

- ◆ Identifying the danger of instability and decision-making whether remedial actions are necessary.
- ◆ Selecting of the most effective actions to prevent instability from the arsenal of available remedial actions.
- ◆ Determining the size of the corrective remedial actions.

3.4.2.1 CECS: Structure and principles of operations [15], [16], [22]

A typical structure of a CECS is shown in Figure 3.9. Blocks S₁, ..., S_n are sensors installed in the different parts of the system collecting the data regarding the current state of the system. Through a telemetry system, this data is channeled to the CECS Computer. This computer

estimates the current state of the system, simulates emergencies, and determines remedial actions required to prevent instabilities for all specified contingencies. Selected remedial actions are stored in the memory devices M_1, \dots, M_k . The CECS process is repeated automatically and periodically to follow changes in power flow conditions. The triggering devices T_1, \dots, T_m are monitoring certain key parameters changes in the system used to detect specific emergency conditions. These parameters can be similar to the parameters used in the relay protection triggering mechanisms, or they can be some other parameters such as generator's acceleration, voltage dips, etc. If a specific disturbance is detected, a signal is generated by the corresponding triggering device and sent to the relevant memory devices. The memory devices, activated by the triggering signal, release pre-calculated emergency control signals to control devices C_1, \dots, C_s executing remedial actions.

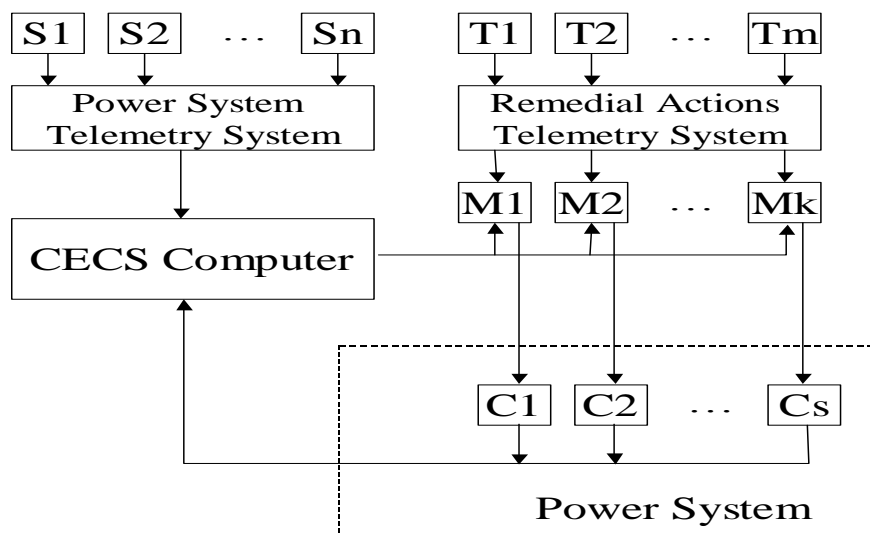


Figure 3.9: CECS Structure

3.4.2.2 CECS: Brief description of the algorithms [15], [16], [21], [22]

The CECS system shown in Figure 3.9 is an example of a system based on the remedial actions pre-calculated at normal operating conditions (BEFORE principle). There are also systems based on the AFTER principle where remedial actions are calculated in emergency conditions. The AFTER systems are mainly used in local emergency control systems described in the next Section. Among the BEFORE CECS algorithms, there are non-adaptive (I-BEFORE) and adaptive (II-BEFORE) algorithms.

I-BEFORE. The non-adaptive algorithms are based on the stability boundaries pre-calculated offline beyond the CECS cycle and usually approximated by polynomials in coordinates of controllable parameters. Remedial actions corresponding to particular emergency conditions are also pre-calculated and stored in a special table.

Within the CECS cycle, the CECS computer algorithms solve the following problems:

1. State estimation of the current operating point.
2. Positioning of the current operating point is against the approximated stability boundary.
3. If the operating point is found outside the boundary, a pre-calculated remedial action is selected from the table to bring the operating point back inside the stability boundary.

The procedure is repeated for each simulated emergency.

II-BEFORE. In adaptive CECS, remedial actions are calculated directly within the cycle for each of the simulated emergencies. The procedure includes the following steps:

1. Fast calculation of the post-emergency power flow.
2. Fast calculation of the stability margin.
3. Fast calculation of remedial actions when they are required.

To fit these calculations into the CECS cycle, simplified models are employed at each stage.

3.4.2.3 *Examples of the centralized emergency control systems*

Several leading power system research institutions have been participating in developing principles and algorithms for CECS. The main developers are Energosetproekt, NIIPT, VEI, and others [15]. There are 10 CECS systems, which control large regions of the UPS under emergency conditions [16], [23]. These include the CECS systems of the 500 kV network of the Ural IPS (NIIPT), 1150/500 kV network CECS at the Itat Substation (Energosetproekt), and others [15].

3.4.3 **Some local emergency control and protection devices – 3rd line of defence**

Russia's protection and emergency control systems include multiple elements; some of them are not widely known or used in Western countries. These elements represent a common whole system distributed emergency control system that is structured, designed, tuned, prioritized and coordinated according to the system conditions, protection functions, selectivity, and reservation. Similar to the US grid, this system is triggered by local parameter variations and applies local remedial actions; at the same time, in some extent, it is designed to address more general tasks of coordinated protecting of the entire control area and even the entire Unified Power System and preventing secondary failures and wide-spread cascading developments. The Russia's coordinated emergency control system also provides a coordinated protection of key transmission and generation facilities as well as inter-area transmission lines. The high-level control centers are responsible, and have sufficient authority to ensure adequate protection of key facilities in the grid and to make sure that the entire decentralized protection and emergency control system is coordinated and operates as a whole without conflicts between local area subsystems, "blind spots", and that the local failures are not propagating through the system.

3.4.3.1 *Transmission lines relay protection [16], [23]*

All main transmission lines (TL) in Russia are protected by high-speed relay protection (RP), mostly using carrier current phase comparison. On 750 and 1150 kV lines, a more sophisticated RP is used in which two methods of fault detection are combined: directional (used during symmetrical three-phase operation) and phase-difference (used in two-phase operating conditions during the cycle of one-phase automatic re-closing). Transformers and bus bars are equipped with the high-speed RP with the time of operation ≤ 20 ms.

The most difficult problem is fault clearing in the case of main RP or circuit breakers failures. The oldest type of the back up RP is the remote back-up design providing fault clearing in the cases mentioned above. Nowadays, the local back up RP is added – circuit breaker failure protection (CBFP), which results in lesser time for short circuit clearing and better sensitivity and selectivity. If a circuit breaker fails to open, CBFP gives commands to open all neighboring circuit breakers. CBFP is installed at all main substations and power plants. The CBFP time delay is $\sim 0.3-0.4$ s at 330-1150 kV substations and ~ 0.5 s at 110-220 kV substations.

3.4.3.2 Automatic flow limiters

The Automatic Flow Limiter (AFL) is a special protection system invented and widely used in Russia [16], [23]. Its purpose is to automatically prevent overloads on the transmission facilities under normal and contingency conditions. This system significantly increases grid reliability by preventing transmission line triplings caused by stability conditions or overloads. By doing so AFL helps to prevent further aggravation of system problems and cascading. AFL operates as a 'watchdog'. If the controlled power flow is found within the limits set for both directions, the limiter does not operate. When the controlled flow exceeds the limits, the Automatic Flow Limiter starts to regulate the designated power plants on the both sides of the line maintaining an overall power balance in the system. AFLs are fast acting emergency control systems with the time constant of about 15-30 s. The AFL operation is coordinated with the other control systems such as the Automatic Frequency and Flow Control. Potential conflicts between these two systems are resolved by giving the higher priority to the Automatic Flow Limiters as an emergency control device.

3.4.3.3 Automatic system separation

Automatic system separation (AS) is used in Russia as an emergency control measure to prevent instability, eliminate asynchronous regimes or to preserve auxiliary load supply capability on power plants by isolating designated generation units [21]. AS is performed by tripping transmission lines connecting different parts of the system or by opening busbar breakers at substations. Stability-oriented AS schemes are triggered by events (e.g. line tripping) or by some other criteria such as increasing power flows, voltage angle differences, etc. In the USA, this effective measure has recently become a subject of research work [24].

The automatic systems preventing asynchronous regimes are extremely important in preventing the blackouts and increasing the overall survivability of a power system. They analyze and compare currents and voltage phase differences on the controlled lines. The system separation signal is generated after 2-3 asynchronous swings. In cases where a real danger of a fast development of the asynchronous regimes (within 1-2 asynchronous swings) with multiple frequencies exists, the AS schemes are used that react to occurrences of significant angle differences on the controlled lines (usually in the range 90-180 degrees). The most difficult task is to determine the configuration of the regions that need to be separated.

The automatic isolation of designated black start units is triggered by deep reduction of the system frequency (up to 45-46 Hz). Obviously such reductions may only occur as a result of severe cascading failures. The main objective here is to keep some generation units running to start-up power plants later during the system restoration process.

3.4.3.4 "Strong action" PSS

The Power System Stabilizers (PSS) installed on many generators in Russia have a different structure, use additional input signals, and are thoroughly tuned to ensure their best performance in the system and coordinated operation with the other PSSs. They are called the "strong action" PSSs, which allow to increase significantly the steady-state stability margin (by ~10%), effectively damp oscillation, and stabilize transient processes. They also help to prevent sudden reductions of nodal voltages. Comparing to the PSSs used in other countries, the "strong action" PSS systems employ derivatives of the input parameters and use more significant gains in their stabilization channels.

An example of such a system (thyristor excitation system) is given in Figure 3.10 [22]. PSS input signals are generator's voltage V_G , its derivative \dot{V}_G , and setpoint V_{G0} ; frequency ω_V , its derivative $\dot{\omega}_V$, and setpoint ω_{V0} ; current in the excitation winding i_f and its derivative \dot{i}_f . The summation block Σ_1 amplifies and sums the input signals. The saturation blocks limit the signal magnitudes. The second summation block Σ_2 is used to add the forced excitation signal ΔV_F , and the excitation winding e.m.f. E_{qe0} determined in the original condition.

The “strong action” PSS systems control the excitation winding voltage without a dead zone with the time constant of 0.01-0.02 s and with the ability of increasing it by 1.6-4 times. The set point control using V_{G0} is relatively slow (with the speed of several percent per second). The forced excitation entry (see [FE] block in Figure 3.10) allows boosting the generator's terminal voltage rather quickly. E.g., if the forced excitation signal ΔV_F constitutes 5-10% of V_{G0} , the terminal voltages increases by the corresponding 5-10% in 0.3-0.5 s. The [FE] entry is used as a dynamic remedial action to oppose sudden declines of system voltages [22]. It is also used by centralized emergency control systems for the same purpose [15].

Regulators of this type are installed on all hydro and thermal generators rated 100-200 MW and more [23].

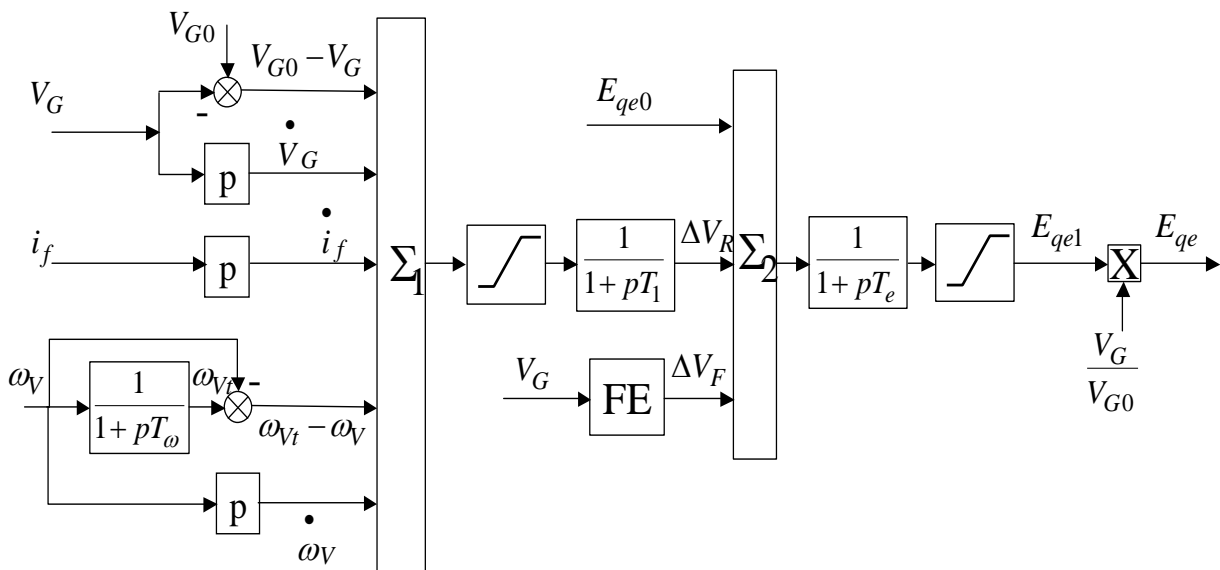


Figure 3.10: Example of “Strong Action” PSS

3.4.3.5 Voltage support from generators

The Russian reliability standards require all generators and synchronous condensers to be equipped with power system stabilizers and forced excitation systems [12]. It is also required to boost the excitation e.m.f. on generators to its maximum acceptable levels (not less than twice its nominal value) at significant voltage declines. At emergency conditions, a short-term overload on generators is permitted. For instance, the stator current can be increased by 10% from its nominal value for 60 min, and by 50-100% for 1 s. The rotor current is allowed to be increased by 6% for 60 min, and by 100% for 20-30 s. These numbers depend on the type of the rotor and stator cooling systems.

3.4.3.6 *Fast valving and turbine torque restriction [21]*

The fast turbine valving is an automatic short-term measure used to minimize the kinetic energy gained during the fault and the following pause before re-closing the circuit breaker. The valving is performed by temporary closing the valve that regulates the steam flow from the steam generator to the turbine. It is triggered by the fault. Due to the inertia of the steam mass, there is a ~0.2 s delay in the actual response. The resulting decrease of the mechanical torque helps to reduce acceleration of the generator's rotor. The size, duration, and the shape of the control impulse is limited by the danger of an excessive deceleration of the rotor with the resulting instability at the second or subsequent swings. If the re-closing is not successful and the circuit breakers open again, the turbine torque restriction is usually applied. This measure restricts the mechanical torque during the post-fault condition. It is triggered by the fact of unsuccessful fault clearing. It performs to a certain minimum turbine load level dictated by its technology, usually to 50-60% of the nominal load. If a further reduction is needed, the automatic generator tripping is executed as it is described below.

3.4.3.7 *Dynamic breaking*

To ensure stability at the first cycle of synchronous swings at significant disturbances such as three- and two-phase faults nearby a large power plant, it may be required to apply more significant stabilizing measures. One of them (used in Russia) is the dynamic breaking. Dynamic breaking automatically applies an additional electric load. This is a parallelly or sequentially connected breaking resistor. Switching is performed using fast thyristor-based systems.

3.4.3.8 *Automatic generator tripping to provide stability [21]*

This type of emergency control is used to prevent instability in contingencies related to the tripping of network components and the corresponding weakening of the transmission paths. Switching is performed by generator or unit breakers with the minimum possible delay following the disturbance. The switching is performed no later than 0.2-0.5 s after the disturbance. The stabilizing effect is provided due to the reduction of the power flow in the lines forming the stability limited cut set during the transient process and in the post-transient system state. Generator tripping helps to increase the decelerating energy by sudden reduction of the equivalent mechanical torque provided by the generators' prime movers. This positive effect could be mitigated due to the reduced electrical torque caused by voltage declines after the generation trip. In this situation, the "strong action" PSSs on the remaining generators help very much to support voltage level. Usually, the generators selected for the tripping are located electrically far away from the critical cut-sets.

3.4.3.9 *Underfrequency and undervoltage load shedding*

This emergency automatic system is generally similar to the one used in the USA. The difference is in the stronger coordination of these important systems, absence of geographical limits in selecting and prioritizing interruptible loads, unified and strictly enforced principles of operation, well developed staged, deeper, and timed sequence of operations. As a result, the Russian grid can withstand severe reductions of frequency and voltages while preserving the overall system reliability and the most important loads. The objective of the Russian underfrequency relaying

system is to eliminate any possibility of frequency reductions below 45 Hz¹³, limit frequency excursions below 47.5 Hz by 20 s, and below 48.5 Hz by 60 s.

Underfrequency relay system consists of two main stages with a well-developed selectivity of frequency settings and time delays [16], [18], [23]:

- ◆ *Stage I* is the fast response ($t = 0.1 \div 0.3$ s) stage that operates in the range of 48.5 ÷ 46.5 Hz. It prevents sudden frequency drops in the beginning of a large frequency disturbance. Within Stage I, there are different settings for different loads that differ by 0.1 Hz. The size of load curtailment for each setting is approximately the same.
- ◆ *Stage II* is designed to restore the normal frequency if it remains at a low level for a longer time. It is also activated in case of additional active power deficiencies that may arise during emergency spreading. The entire series of Stage II settings is set at a value equal to the upper setting of the Stage I or slightly higher, with the time delays between settings of 3 s in the interval from 5 to 90 s. Longer time settings of Stage II provide time for mobilizing the power system generation reserves.

Some deficient areas in the United System receiving power from the rest of the system are equipped with *Stage III* – a high-speed underfrequency relaying with the highest setting of 49 Hz. It prevents overloads on the supplying tie lines. To restore the power system frequency more rapidly and to decrease the amount of load disconnected by Stage II, the operating reserve must be expeditiously activated by loading the rotating reserve units, fast start-up, connection to the network, loading the hydroelectric units as the frequency is decreased to 49.3 Hz. In this situation the rapid loading of the hydro and thermal units, which operate partly loaded, is effected. Since a long operation of electrical motors at a reduced frequency may cause a complete loss of thermal power plants, contingency procedures are enforced to separate auxiliary equipment from the network and to supply them with special generators. Schemes that isolate some thermal power plants (or some of their units) with approximately balanced load and generation are applied usually with two thresholds at 45-46 Hz and 0.5 s; 47 Hz and 30-40 s. After elimination of underfrequency condition, power supply of disconnected loads will be restored automatically by automatic frequency re-closing schemes.

Undervoltage relaying. Sometimes contingencies and extreme local imbalances of reactive power make it necessary to use special measures, which limit undesirable voltage deviations. When undervoltage occurs, the automatic disconnection of shunt reactors on ultra-high-voltage grids may be used to raise the voltage. Also, automatic boosting the excitation of generators and synchronous condensers, up to overload levels, which are permissible for short periods of time, plays an important role in preventing undervoltage-induced fault spreading. For especially large shortages of reactive power, threatening the loss of steady-state stability ("voltage collapse" type of faults), the automatic voltage load shedding is used. These devices are equipped with two voltage relays having high reset factor with settings equal to 0.85 of the nominal voltage and time relays. There are typically two or three steps of the undervoltage relay systems with various time settings in the range of 5-15 sec.

3.4.3.10 *Overfrequency and overvoltage protection*

The automatic overfrequency protection system prevents frequency increases above or equal to 55 Hz, that can cause further thermal unit trips. This system also protects hydro units from the

¹³ An approximate evaluation of the minimum frequency at which the cascading failure called "the avalanche of frequency" begins.

exposure to frequency increases of 60 Hz or more. The overfrequency protection system decreases the frequency by tripping hydro units or by controllable network separation. Taking into account the dangers of the power system operation with high frequency, the system is implemented with two stages: the first one (main stage) that trips selected hydro units at 51.5 Hz, and the second one (back-up stage) that operates at 52-53.5 Hz. The second stage isolates selected thermal units in the regions with approximately balanced load and generation.

The automatic overvoltage protection is provided at 330-1150 kV substations to prevent electric equipment damages in case of one-side transmission line disconnections. Possible dangerous overvoltage may also occur due to electric resonance conditions. Surge arresters are the main devices that limit overvoltages to a permissible level. For example, overvoltages on the 500 kV network should not exceed 1.7 p.u. Overvoltages of a lower level can be dangerous as well if they persist over a longer period¹⁴. The Russian overvoltage protection relays address these differences. They consist of the following components: the initiating, selecting, and time delaying elements. The initiating element, containing three voltage relays measuring phase voltages, detects the fact of an inadmissible voltage increase. The selecting element determines the transmission line that caused the increase. The time delaying element provides the required operation delay. Usually, the overvoltage protection system has two stages: the “sensitive” and “coarse” stages. In case of an inadmissible voltage increase, the system (at any stage) turns in the shunt reactor (if it has been disconnected); then, if the voltage does not decrease, trips the idle transmission line; and finally, if line’s circuit breaker fails to open, opens all circuit breakers connected to the failed one. Operating voltages for the “sensitive” stage are 0.15-1.25 p.u., and for the “coarse” stage they are 1.4-1.5 p.u.

3.5 Emergency Control in ENTSO-E RG CE

Operational security of ENTSO-E RG CE is based on the n-1 criterion. Emergency control is applied beyond n-1 cases. Automatic emergency control procedures are Load-Shedding and Out-of-Step protection of Generators. Further emergency control actions are based on manual execution in the control centers based on an exchange of information among interconnected TSOs.

3.5.1 Load-Shedding [25]

ENTSO-E RG CE recommends that its members should initiate the first stage of automatic load-shedding in response to a frequency threshold not lower than 49 Hz.

- ◆ Sudden failure of 3000 MW of the generating capacity in normal operation without other disruptions have to be corrected solely by the action of the primary controller without frequency sensitive action triggering of load-shedding.
- ◆ In case of a frequency drop of 49 Hz the automatic load-shedding begins with a minimum of 10 to 20% of the load. Each TSO determines shedding plans on his own. In case of lower system frequencies, the synchronously interconnected network may be divided into partial networks. In this case, far more difficult conditions will arise in those partial networks affected by a shortfall in capacity. For this reason, the staggered operation of relays for load-shedding in response to a frequency criterion will allow the system load to be reduced to a sufficient extent for the restoration of balanced conditions in these partial

¹⁴ For instance, the 750 kV equipment is designed to withstand overvoltages of 1.1 p.u. for 1200 s, 1.3 p.u. for 20 s, 1.88 p.u. for 1 sec, and of 1.98 p.u. for only 0.1 sec.

networks, before the threshold for the isolation of plants for the supply of auxiliaries or the tripping of generators is reached.

- ◆ Load-shedding should be performed at trigger frequencies of 48.7 Hz and 48.4 Hz (or as in France at 48.5 Hz and 48.0 Hz) to the amount of about 10 to 15% of the load. The partners accept load-shedding also if the failure occurs outside the control area of the respective TSO. Triggering frequencies should be modified by the competent TSO – slight dissipation of the triggers will cause gradual increasing of the load.
- ◆ Load-shedding in each stage shall be established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

3.5.2 Loss of synchronism [26]

In case of a loss of synchronism between generating units, the latter should be islanded upon their own auxiliaries or some parts of the network should be separated. Such islanding is implemented to accelerate the restoration of the network after a collapse.

3.5.3 Recommendations for Power Plants [25]

The following possible measures for emergency conditions are related to power plants:

- ◆ At 49.8 Hz, quick-start power plants should be connected to the grid.
- ◆ Under emergency conditions and if applicable, the operating mode of (thermal) generating units should/may be changed from power pressure into speed control. A very fast rate of change can be possible within the whole operating range, yet being very uneconomic.
- ◆ Power stations automatically disconnect at 47.5 Hz without time delay, and shall safeguard auxiliary service supply. Operation of power plants below this frequency is endangered.

3.5.4 Tie-lines opening policy [26]

Opening a tie-line has to be assessed and agreed upon in advance in a transparent way; automatic opening may be performed when given events occur and if certain thresholds are exceeded (e.g. overload damage of the equipment); this should contribute to the speed up of a restoration sequence. TSOs have to agree on points of manual and automatic disconnection in case of frequency drop, overloading, loss of synchronism. Urgent opening can be carried out in emergency situations in case of physical danger to human beings or installations without prior information to neighbouring TSOs involved. To keep the interconnection in operation as long as possible is of utmost importance, but shall be consistent with the operating constraints. Therefore any manual emergency opening of tie-lines shall be, by preference, announced in advance or justified ex-post with neighbouring TSOs.

3.6 Protection Systems

3.6.1 Classification of system protection schemes

The function of the protection systems is to promptly remove from service any element of the power system that starts to operate in an abnormal manner. Their purpose is to remove the faulted equipment from the power system as quickly as possible, so that the integrity and stability of the remaining system is maintained. Table 3.4 presents a classification of protection schemes.

The protection systems shall operate reliable must be dependable, and secure. The protection schemes of transmission lines and power transformers shall be designed with redundancy;

therefore, duplicate of the main protection system must be used. This duplication means use of protection equipment from a different manufacturer, or based upon different principle of operation.

Table 3.4: Classification of SPS

According to input variables	According to importance for stability keeping	According to principles of stability analysis	
		ENTSO-E RG CE	IPS/UPS
<ul style="list-style-type: none"> ◆ response-based SPS ◆ event-based SPS 	<ul style="list-style-type: none"> ◆ type I – that use some operating criteria contingencies ◆ type II – that use some extreme contingencies 	<ul style="list-style-type: none"> ◆ behavior confirmation – off-line pre-fault ◆ behavior assumption – on-line pre-fault ◆ behavior prediction – on-line post-fault 	<ul style="list-style-type: none"> ◆ II – BEFORE ◆ I – BEFORE ◆ I – AFTER and II – AFTER

3.6.2 Current status of the protection system at the interface

ENTSO-E RG CE and IPS/UPS power systems interface area has a special role taking the inter-area location into consideration and therefore the applied protection and automation systems must not limit the energy transit flows and activate inter-area oscillations, power swings which can occur by the interconnected ENTSO-E RG CE-IPS/UPS power systems.

The philosophies of the protection systems on both sides of the interface area are similar. The applied protection schemes in IPS/UPS constitute effective protection systems with a complete redundancy compatible with the systems used in ENTSO-E RG CE.

In the IPS/UPS and in the ENTSO-E RG CE member power systems, two separate sets of protection (two distance protections or one line differential and one distance protection) are used for transmission lines (on 220 kV and higher voltage level) and in power transformers.

The protection functions realized on the interconnecting lines or in the coupled substations which are relevant from the system stability point of view or which are influenced by the physical phenomena of the power systems during a power swing or an inter-area oscillation e.g.:

- ◆ Current and time delay settings of the phase-overcurrent relays (overload protection) on the tie-lines;
- ◆ Second zone time delay settings of the distance protections on the tie-lines;
- ◆ Use of the Circuit Breaker Back-up Protections and their settings (time delay) in the coupled substations;
- ◆ Pause time of the 3-phase autoreclosing and the settings of the synchrocheck function (ΔU , $\Delta \alpha$, Δf) on the tie-lines;
- ◆ Use of the Power Swing Blocking (PSB) and Out-of-Step Tripping (OST) functions and their settings;
- ◆ Use of the over/undervoltage protections (in the case of line tripping) and their setting values (voltage and time delay);
- ◆ Use of the under/overfrequency relay functions on the tie-lines in the interface area and near to the interface area and their settings (time delay and direction).

Some differences exist in the concepts, but the greatest differences are to be found in the practical implementation. In UPS most of the relays are of the electromechanical (analog) type,

while in extra high voltage systems a number of the digital relays with improved characteristics are installed. Table 3.5 shows the proportion of the different types of installed protection systems on the ENTSO-E RG CE and IPS/UPS side of the interface area.

Table 3.5: Proportion of the different types of installed protection systems

Protection functions (numbers of installed systems in ENTSO-E RG CE-IPS/UPS)	Type	ENTSO-E RG CE			IPS/UPS		
		Analog	Static	Digital	Analog	Static	Digital
Line protection	(9-9)	-	2 / 22%	7 / 78%	2 / 22%	-	7 / 78%
Autorecloser	(9-9)	-	2 / 22%	7 / 78%	6 / 67%	-	3 / 33%
Busbar protection	(9-5)	-	4 / 44%	5 / 56%	5 / 100%	-	-
Power transformer protection	(9-5)	-	1 / 11%	8 / 89%	3 / 60%	-	2 / 40%
Under/overvoltage protection	(6-4)	1 / 17%	1 / 17%	4 / 66%	4 / 100%	-	-

Table 3.6: Current setting values of the protections

Substation 1	Substation 2	Voltage, kV	Fault clearing time in first zone of Distance Protection, ms	Second zone setting time of Distance protection, ms	Pause time of 3-phase Autorecloser, s	Circuit breaker backup/failure protection delay time, ms (Substation 1/ Substation 2)
Rzeszów	Khmelnitski	750	100	500	0,5	150
Vel'ke Kapusany	Mukachevo	400	100	700	0,5	400/150
Sajószöged	Mukachevo	400	100	400	0,6	180/150
Albertirsa	Zahidnoukrainska	750	100	600	0,9	250/150
Kisvárd	Mukachevo	220	100	400	0,6	250
Tiszalök	Mukachevo	220	100	400	0,6	250
Roşiori	Mukachevo	400	100	400	-	150
Isaccea	Pivdennoukrainska NPP	750	100	400	-	150
Isaccea	Vulcăneşti	400	150	400	-	150

Table 3.6 shows the current setting values of the first and second zones time of the distance protections and the pause time of the 3-phase autorecloser (AR) on the transmission lines and the circuit breaker backup/failure protection (CBFP) delay time in the substations in the interface area. The setting values of CBFP shall be reduced and coordinated to max. 150 ms.

To reduce the time of CBFP on the 220 kV lines the existing devices of CBFP should be changed to modern digital devices. In addition it is recommended to change existing slowly operating circuit breakers in the area near to the interface, too.

3.7 Conclusions

The two synchronous areas have been developed and operated differently for some considerable length of time. Due to their independent development the major differences in system structure and certain operation philosophy variations exist between ENTSO-E RG CE and IPS/UPS. These differences are summarized in The Western synchronous zone is characterized by a high

rigidity of the system, so generally the thermal limits of the elements are used as criteria for long term analysis and planning. The Eastern synchronous zone contains a considerable number of long and therefore weak transmission lines. In these conditions it is necessary for the Eastern synchronous zone, first of all, to take into account stability margins in respect to active power and voltage as well as the overcurrents in the initial and normative post-fault schemes. A specific feature of the IPS/UPS synchronous zone is the extensive use of emergency control automatics, which significantly contribute to ensuring system security. Such technical solution is a feasible measure to ensure the system integrity in case of stability problems arising from the exceptional grid topology of IPS/UPS. While both systems follow the n-1 criteria, in IPS/UPS a wider range of means is used to overcome the consequences of disturbances (i.e. power imbalances, grip elements tripping or overloads, violations of voltage limits, etc.): protection, re-dispatching and automation actions comprising load and generation shedding.

Table 3.7.

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Table 3.7: Difference between ENTSO-E RG CE and IPS/UPS operation principles

		ENTSO-E RG CE	IPS/UPS
Organized principles		<ul style="list-style-type: none"> ◆ Decentralized dispatch structure ◆ n-1 criterion 	<ul style="list-style-type: none"> ◆ Centralized dispatch structure ◆ Using of system protection schemes
Technical principles	Primary control	<ul style="list-style-type: none"> ◆ maximum disturbance is 3000 MW ◆ dead zone for governors is ± 10 mHz ◆ dead zone for primary control system is ± 20 mHz ◆ load/frequency drop is 20 000–25 000 MW/Hz 	<ul style="list-style-type: none"> ◆ primary disturbance is 1200 MW ◆ maximum frequency deviation is ± 50 mHz ◆ there are many governors with the dead zone 0.2 Hz ◆ load/frequency drop is 10 000–30 000 MW/Hz ◆ in order to meet the European standard, 10% generator units governors are to be modernized
	Secondary control	<ul style="list-style-type: none"> ◆ based on boundary control blocks frequency deviation ◆ control systems are used in areas of control 	<ul style="list-style-type: none"> ◆ based on tie-lines power flow control ◆ has one secondary regulator, several regulator for power ◆ flow control with frequency correction and a number regulators for power flow limitation ◆ some power plants has possibility for tertiary control

The solutions of power and frequency control currently applied in the ENTSO-E RG CE and IPS/UPS differ significantly from each other. The most important difference is the organization philosophy of frequency control that is decentralized in ENTSO-E RG CE and centralized in IPS/UPS, which directly comes from the structure of these power systems. As a consequence of this the secondary control in power systems of IPS/UPS means the control of tie line flows (except the Central region which is solely responsible for frequency control) in contrary to ENTSO-E RG CE, where secondary control always means control of ACE (area control errors) on control block borders. Nevertheless power and frequency control solutions currently applied in ENTSO-E RG CE and IPS/UPS are compatible i.e. they do not exclude synchronous coupling of these two areas.

Synchronous coupling of the huge ENTSO-E RG CE and IPS/UPS power systems by a relatively weak interface naturally leads to large primary control flows, up to 1500 MW over the interface, what in turn requires permanent reservation of free transmission capacity of this amount out of the total transfer capacity of the interface. Apart from the interface this refers also to some internal congested areas within ENTSO-E RG CE and IPS/UPS.

In principle the available reactive power reserve of all synchronous generators, synchronous compensators and compensation reactors in ENTSO-E RG CE and IPS/UPS power systems is sufficient to keep the voltages in the acceptable limits during the winter peak load and summer light load conditions. The switching of the on-load tap-changers of the transformers allows the distribution of reactive power and optimization of the voltage profile and the power losses in the power systems. However, all compensation equipments for reactive power near to the interface are to be inspected and tested in operation before starting the coupling ENTSO-E RG CE and IPS/UPS operation.

Regarding relay protections there are some differences in the concepts, but the greatest differences are to be found in the practical implementation. In UPS most of the relays are of the electromechanical (analog) type, while in extra high voltage systems a number of digital relays with improved characteristics are installed. But in general the philosophies of the protection systems on both sides of the interface area are similar. The applied protection schemes in IPS/UPS constitute effective protection systems with a complete redundancy compatible with the systems used in ENTSO-E RG CE.

Potential power exchanges between ENTSO-E RG CE and IPS/UPS are limited mainly due to internal congestions. Therefore, a coupling would require investments in the transmission grids on both sides of the interface in order to maintain the transfer capacities available to the markets at present in both synchronous areas. Additional transmission system investments are necessary to ensure significant increase of power exchanges.

3.8 Recommendations

Synchronous coupling between ENTSO-E RG CE and IPS/UPS is one option for interconnecting the two systems. As the implementation phase for those measures and conditions is recognized as a long process, a synchronous coupling can be considered only as a long term perspective. In order to achieve a joint, world-largest electricity market platform between ENTSO-E RG CE and IPS/UPS synchronous areas the construction of HVDC links between the interface countries may be considered as a medium-term alternative solution for system coupling.

Economical benefits that are mostly associated with the extension of power systems are to some extent countervailed by technical drawbacks. In the first place the unabated propagation of

disturbances and their consequences through the interconnected system has to be prevented. As support to the creation of a joint electricity market platform between ENTSO-E RG CE and IPS/UPS in a medium time horizon the construction of HVDC back-to-back links between the interface countries may be considered as an advantageous alternative solution. Ultimately, due to their technical advantages, back-to-back links may result in a more cost-effective and thus “easier to realize” perspective.

UCTE IPS/UPS study [6] evaluates necessary investments for the interconnections between UCTE and Eastern Europe countries. The investments to the asynchronous (with BTB links) interconnection were evaluated as two times less than to the synchronous option.

4 TASK 1.5. STUDY OF EU AND RUSSIAN LEGISLATURE AND ELECTRICITY MARKETS AND THEIR POSSIBLE DEVELOPMENT IN CASE OF INTERCONNECTING BOTH SYSTEMS, FOR CREATION OF REALISTIC SIMULATION SCENARIOS

4.1 Economic and regulatory drivers and barriers of new interconnections

The EU Commission and the EU Member States with national regulators and stakeholders work toward the creation of an efficient and effectively competitive single electricity market. An important issue is the removal of all avoidable impediments to cross-border electricity exchanges allowing a free flow of electricity between Member States.

Figure 4.1 gives an overview of potential or already established electricity markets within the EU.

Identification of economic and regulatory drivers and barriers of new interconnection is important for assessment of local or regional initiatives to increase interconnection capacity.

This Section recalls the main aspects related to economic and regulatory drivers and barriers of new interconnections in Europe.



Figure 4.1: Potential regional electricity markets within the EU (source EC 2004)

4.1.1 Advantages, drivers and benefits of cross-border interconnections

This Section summarises the main advantages and drivers of investments in interconnection of different power systems:

- ◆ promotion of competition and efficiency at both sides of the interconnection;
- ◆ existence and possible reduction of price differences between regions, which could be related to differences in fuel mix and primary resources;
- ◆ increase of system reliability, whose additional gains however normally become progressively less important when interconnections become stronger.

Connecting together all participants across the interconnected transmission system makes it feasible to select the cheapest generation; a firm interconnection of different markets promotes increasing of liquidity and competition. It reduces the possibility to abuse market power and it suppresses the higher electricity prices that might have arisen from such abuse.

Existence of price differences between regions is one of the most important economic drivers for interconnection. Interconnectors are the vehicles for price arbitrage between markets. Partly, the price differences may result from the lack of a level playing field for generation in the different parts of the European electricity system (e.g. tax regimes, subsidies, environmental legislation and market structure). It is worth to note that price differences that occur due to the lack of level playing field may not be structural and therefore could be a possible “false driver” for interconnection: price differences that result from different regulatory structures may not form a basis for structural exchange, as it is expected that these differences will fade away in the long run. Differences in fuel mix and load patterns also involve price differences. Different countries have different generation mixes; this difference can lead to prices for wholesale electricity that vary by a factor of two or three [27]. Nuclear power has relatively low variable costs, and is a typical base-load type of generation; gas, on the other hand, is relatively expensive, but can be flexibly used to meet peak load. The differences in fuel mixes between countries or regions are linked with the availability of primary resources; in the long run, countries or regions that have cheap availability of specific primary resources will probably concentrate on generating technologies that match with these resources. Specific base-load technologies (nuclear and coal) require different fuels (nuclear, oil, coal...) with respect to typical peak-load technologies (gas and hydro); the long-term trend of exchange will probably head in the direction of intra-day exchange: ‘base-load countries’ exporting during off-peak hours and importing during peak-hours, and ‘peak-load countries’ vice versa. Besides, there could be a structural need for exchange if peak demand falls on different times within a day (particularly of importance for geographically, east-west spread areas). Furthermore, different demand characteristics can involve different load curves, which justify structural exchanges. By connecting regions with different load patterns, it may be possible to meet demand more efficiently, as the aggregated demand curve is flatter.

System reliability is mainly related to: increase of frequency regulation with a major generation capacity, stable price development in long-term between interconnected markets that is an important indicator for investors, security of supply by allowing a more diverse mix of primary energy sources.

4.1.2 Barriers to and costs and drawbacks of interconnection

There are investment costs, which could be high for building new interconnections. These investment costs and the long lifetime of interconnection and transmission lines cause TSOs and regulators to be cautious with investment decisions because of the relevant uncertainty about future scenarios in long run.

Energy losses caused by electricity transmission, which depend not only on the length of the interconnection lines themselves, but also on the total distance over which electricity is transmitted (length of interconnection and of additional pattern within areas interconnected).

Relatively small cross-border capacities and insufficient allocation of these capacities can lead to congestion within the EU, which could hinder electricity exchange with neighbouring regions; if electricity cannot sufficiently flow across national EU Member State borders, interconnection with non-EU regions can at the most offer benefits at a local (national) scale only.

Interconnection capacity competes with domestic generation; therefore interconnection could lead to an increasing import dependency, which may create political resistance.

An important barrier is also the possible opposition of citizens in the areas where the transmission and interconnection lines have to be built.

4.1.3 Regulatory issues

Trade between countries/regions is impeded or distorted because of the differences between market designs and rules. Harmonization of key market rules is fundamental for trade opportunities; regulatory issues concern: gate closure, imbalance arrangements, firmness of transmission access rights, and type of tariff regulation and unbundling of interconnectors from market competitors. On the other hand, the above discussion does not necessarily mean that full harmonisation of all trading rules and arrangements is required; indeed regulatory arrangements need to be independent, with regulatory processes characterised by transparency, objectivity and consistency.

4.2 Study of EU and Russian legislature

This Section aims at investigating the legislative and regulatory framework of the electric power systems (EPSs) of both the Russian Federation (RF) and the European Union (EU). In fact, in order to individuate the most suitable way to organize the parallel operation of Russian and European EPSs it is important that the legislation and regulatory features of both Russia and EU are taken into account.

4.2.1 Russian legislation

The legislative basis and regulation of electric power industry in Russia are determined by the law “On Electric Power Industry” [28]. Another document, which was especially important during the restructuring period, is the law “On Specific Features of Functioning of Electric Power Industry during the Transitional Period” [29].

According to these laws the key element of electricity industry regulation is the separation of networks operation and dispatching control from other power system businesses (unbundling). For this purpose it is forbidden to combine transmission and dispatch activities with generating or selling/buying electricity (an exception is made for suppliers of last resort). Companies are not allowed to own simultaneously generation and transmission facilities. Affiliating is also forbidden within one pricing zone of the electricity market, i.e. a generation company may not own stocks of a transmission company and viceversa.

This unbundling principle is not applied to isolated systems where competition is considered as limited. Also, companies are allowed to own and operate transmission lines which are used for the transport of their own production only.

The transmission facilities separated from other power system businesses form the Unified National Electric Grid (UNEG). According to [30] the following transmission lines belong to UNEG:

- ◆ all lines at a voltage level of 330 kV and higher;
- ◆ 220 kV lines connecting power plants (having an installed capacity higher than 200 MW), large consuming nodes (having a connected capacity higher than 125 MVA) and EPS of different constituent entities.

Operation, maintenance and development of UNEG is managed by a specially organized open joint-stock company – the Federal Grid Company (FGC) [31]. According to [28] more than 75% of stocks of the company should belong to the state when the transitional period is over.

Along with the FGC any other company, body or individual can construct new network facilities. The owner of new facilities has a right to connect them to the existing electric networks. But if the new facility falls within the above mentioned criteria for belonging to UNEG, its owner is obliged to conclude a special agreement with the FGC. According to this agreement, the line owner transfers to the FGC the rights to operate the facility, to conclude contracts for the facility usage and to determine conditions of these contracts. Such a line can be put out of operation only if the FGC approves this.

In theory, the line owner can get back the right to operate the line and to conclude contracts if the FGC violates important terms of the reached agreement. However, even in this case the terms and conditions of contracts for the line usage will be based on the regulatory standards.

Prices and tariffs for electricity transmission and for connection to the networks are cost-based. For pricing purposes all the construction and maintenance costs are taken into account as well as rate of profit. Additionally, the regulated network prices can include costs of services provided by the System Operator (SO)¹⁵, taking also the liability insurance into account. The same cost-based principle is applied for the payments provided by the FGC to the owners of network facilities.

The connection costs of new consumers, generators or other facilities are covered by the regulated connection and/or transmission prices. The fee for technological connection can cover only the investments necessary to connect the new network user to the existing network. Part of connection costs can be subsidized from transmission prices. If the connection of a new user causes a bottleneck in the grid, the investments to release the bottleneck should be covered by transmission prices, not by connection fees.

The FGC and its affiliated companies are not allowed to buy and sell electricity and electric power, except for their own needs, loss compensation and technological support of parallel operation with foreign EPSs. If a company affiliated with FGC functions as a supplier of last resort it is allowed to buy and sell electricity as well. FGC is obliged to conclude contracts for electricity transmission. Such a contract cannot be denied by FGC if someone asks to conclude for it.

Dispatching control services in electric power industry are provided by the SO [32]. The SO is an open joint-stock company and all the stocks of the SO should belong to the state when the

¹⁵ Transmission and Distribution System operators are not actually separated in UPS. The functions of Distribution System Operators are carried out by local control centers affiliated with SO UES.

restructuring is over. SO is not allowed to buy and sell electricity except for the cases where parallel operation with foreign EPSs should be maintained. The main goals of SO are to guarantee security of EPS operation and power quality.

Electricity transmission and dispatching control services are considered as “natural monopolies”. For these power system businesses the law “On natural monopolies” is applied [33]. In electricity generation another regulatory element is applied: if a generation company controls more than 20% of the installed capacity or more than 20% of electricity generated within one uncongested area, it is considered as “market dominant” and antimonopoly regulation is applied. Antimonopoly regulation can also be applied if the market share of a company does not exceed the 20% limit but still the company is able to manipulate the market price (market power or abuse).

4.2.2 EU Legislation: Current Directive

The EU policy for electric power industry aims at the three targets of system competitiveness, environmental sustainability and security of electricity supply [34]. The main goals of the electricity markets liberalization and integration process consist in improving power supply services, lowering electricity prices and, thus, increasing competitiveness of European (especially industrial) companies. The EU legislation for electric power industry is mostly based on the Directives and Decisions of the European Parliament and of the Council, as well as on the national legislative provisions of the EU Member States (MS).

The EU Directives have to be mandatorily implemented into the national legislations of all EU MS and establish only the most general principles to be applied to the power system industry regulation. Detailed determination of regulatory methods and forms is left to the legislative and executive bodies of MS.

In the latest years the Directive 2003/54/EC [35] has played the most important role for the electric power industry of EU, determining the common rules for the European electricity market. This Directive is aimed at progressive market opening for competition, elimination of discrimination and higher level of integration of electricity markets of MS.

In accordance with the Directive, MS shall ensure equality of access of EU electricity companies to national consumers. Technical rules establishing the minimum design and operational requirements for the connection of new facilities shall be objective and non-discriminatory. The authorization procedures for new generating capacity should also satisfy objective, transparent and non-discriminatory criteria.

If on the basis of the authorization procedure the generating capacity being built is not sufficient to ensure security of supply, MS can launch tendering or other non-discriminatory procedure for new generation or demand-side management. MS shall designate a body independent of electricity generation, transmission, distribution and supply activities to be a regulatory authority responsible for the tendering procedure.

The Directive pays attention to customer protection. To ensure that all household customers can receive electricity at reasonable prices, MS can appoint suppliers of last resort. Distribution companies shall be obliged to connect customers to their grids under regulated terms and tariffs. It is also important that MS ensure that any eligible customer has the possibility of changing power supplier. Since July 1, 2007, all customers have been eligible.

To provide security of power supply MS shall ensure the monitoring of supply security issues. It can be done by regulatory authorities or by other entities. This monitoring includes current and future supply/demand balance and quality of network maintenance. Measures to cover peak demand and to deal with suppliers outages should also be monitored.

MS shall designate one or more Transmission System Operators (TSOs). TSOs are responsible for:

- ◆ expansion of transmission systems: transmission systems should be reasonably expanded to meet load demands increases and improve security of supply;
- ◆ system operation: TSOs manage energy flows in the system and ancillary services for secure, reliable and efficient system operation;
- ◆ providing information: other TSOs are provided with the necessary information to ensure efficient operation, development and interoperability of the interconnected system while system users being provided with the information for efficient access to the system;
- ◆ ensuring non-discrimination.

If a TSO is part of a vertically integrated undertaking it shall be independent of other activities not related to transmission. Ownership separation of transmission assets from the undertaking is not necessary. To ensure independence of the TSO from the undertaking the following criteria are applied:

- ◆ persons responsible for the TSO management may not participate in company structures dealing with generation, distribution and supply of electricity;
- ◆ appropriate measures should be taken to stimulate persons responsible for the TSO management to act independently;
- ◆ the TSO shall have decision-making rights concerning assets necessary to operate, maintain and develop the network. These rights should be independent from the integrated undertaking;
- ◆ the TSO shall take measures to exclude discriminatory behaviour.

If TSOs are responsible for reserves or loss compensation, they shall procure the reserve capacity and energy according to transparent, non-discriminatory and market-based procedures. Only one kind of discrimination is officially allowed: a MS may require its TSO to give priority to renewable energy or energy produced in combined cycle.

MS shall also designate one or more Distribution System Operators (DSO) to create a secure, reliable and efficient distribution system taking into account environmental issues. DSO must not discriminate between system users and shall provide customers with all necessary information for efficient access to the distribution system. If a DSO is responsible for reserves or loss compensation, it shall procure the reserve capacity and energy according to transparent, non-discriminatory and market-based procedures. During dispatching a priority can be given to renewable energy or energy produced in combined cycle.

If a DSO is part of a vertically integrated utility it shall be independent of other utility departments at least in terms of its legal form, organization and decision making. Ownership separation of DSO assets from the vertically integrated company is not necessary. To ensure the independence of DSO the same criteria so as to ensure TSO independence are applied.

One entity is allowed to combine TSO and DSO activities (combined operator). For combined operator legal, organizational and decision-making unbundling is also applied without obligatory asset separation.

For transmission and distribution systems the principle of third party access is implemented. The essence of the principle is that any eligible customer can access networks without any discrimination. The access is based on published regulated tariffs and technical rules which are applicable to all eligible system users. The system operator can refuse access to the network only if there is no sufficient capacity.

In addition to the third party access principle, another regulatory regime is applied. This is based on direct lines. According to the Directive, MS shall ensure that all electricity producers and undertakings are able to supply their subsidiaries and eligible customers through direct lines. All consumers should have a possibility to be supplied through a direct line by a producer or supply undertaking. The authorization criteria for the direct line construction should be objective and non-discriminatory. The possibility to supply or to be supplied through a direct line should not affect the possibility of contracting electricity through the common grid.

Nevertheless, it is up to MS whether a certain direct line is authorized or not. Authorization for a direct line can be refused if the line can obstruct public service obligations or customer protection provisions.

According to the Directive, MS may decide not to apply the provisions concerning authorization and tendering for new capacity, third party access and direct lines, if their application would obstruct the performance of the obligations imposed on electric companies. However, this is only possible as far as the development of trade is not significantly affected and in contrast with interests of the EU (including competition among eligible customers).

The Directive also requires that each MS designates at least one regulatory authority, which is independent of the interests of the electricity industry. These authorities are responsible for ensuring market and competition efficiency, non-discrimination and monitoring of some market elements, rules and mechanisms. The regulators shall also be responsible for regulation of terms and conditions for connection and access to networks and the provision of balancing services.

4.2.3 EU Legislation: New Directive and Regulations

In September 2007 a new Proposal on the common rules for the European electricity market was presented as part of the so-called EU Third Legislative Package [36], [37], and very recently (July 2009) it has become the new EU Directive on electricity market (Directive 2009/72/EC) [38]. This document starting from the principles contained in the Directive 2003/54/EC brings new regulatory elements to the EU electric power industry. The new Directive 2009/72/EC enters into force on 3 September 2009 and shall be implemented by all EU MS by 3 March 2011, when the former Directive 2003/54/EC shall be repealed.

The background of the new Directive is that legal and decision-making unbundling of transmission networks from other power system businesses is not sufficient since it does not prevent discrimination of market participants in favour of the vertically integrated undertakings. Therefore, it is suggested that ownership unbundling of transmission assets should be granted. MS must ensure that the same person cannot exercise control over a generation or supply company while having control over a TSO or over a transmission system. Viceversa, control over TSO or over a transmission system precludes the possibility of exercising any control over a generation or supply undertaking.

One person is allowed to hold interests in both a generation or supply undertaking and a TSO or a transmission company, but this shareholder should have no controlling or blocking rights in both undertakings, can neither be a member of a board nor appoint board members.

The new Directive suggests also an alternative option. Instead of obligatory ownership unbundling, MS may force vertically integrated undertakings to transfer network management to an Independent System Operator (ISO) or Independent Transmission Operator (ITO). ISO/ITO shall be completely independent of the vertically integrated company and perform all TSO functions.

Towards the establishment of a more integrated and efficient electricity market in the EU, great attention is paid by the Third Package to the improvement of the cooperation mechanisms of regulating authorities. This process has led to the recent creation of an Agency for the Cooperation of Energy Regulators (ACER), which aims to harmonise the regulatory mechanisms of electric power industries of different EU MS (as stated in the Regulation (EC) No. 713/2009 establishing the ACER [39]). The Agency will provide a framework for cooperation of national regulators, monitor the cooperation between TSOs, make regulatory decisions on some cross-border issues and serve as an advisor for the European Commission concerning market regulation issues. The ACER will have close cooperation with ENTSO-E (European Network of Transmission System Operators for Electricity), the newly created association embracing all previous European TSO associations (UCTE, NORDEL, UKTSOA, ATSOI, BALTSO, ETSO) [40]. As far as the technical and market codes are concerned, the Agency will be empowered to ask TSOs to modify their code drafts or to tackle more specific issues in detail. It will also be able to recommend that the Commission make these codes legally binding where voluntary implementation by TSOs seems to be insufficient or unsuitable for certain issues. The ACER will make decisions concerning the regulatory regime to be applied to infrastructure assets connecting territories of two or more MS.

In summary, the new Agency is going to be a supranational regulator with a broad regulatory power in the European electric power industry.

4.2.4 Analysis

The regulation of the electric power industry in Russia is different from the one in the EU. In Russia the electric power industry regulation is centralized: the regulatory provisions consist of federal laws and governmental decrees. In the EU, Member States have currently the power to regulate their electricity industries. The European institutions, like the European Parliament, the Council and the Commission of the European Communities, have a limited regulatory power. The 2003/54/EC Directive [35] deals with the general regulatory provisions and, thus, enables MS to be flexible and to keep a diversity of regulatory methods and approaches within the EU.

The new 2009/72/EC Directive [38] and the new Regulations, part of the EU Third Package [37], will make the EU electricity industry regulation more coordinated and harmonised due to stricter network unbundling, creation of a supranational regulator, unification of powers and functions of the national regulators. However, the extent of electricity regulation centralization will not be the same as the one existing in Russia.

For this reason, only the most common regulatory elements of the EU and Russia can be compared. These elements are:

- ◆ unbundling of electricity networks systems from other power sector activities and the exclusions from the unbundling principle;
- ◆ unbundling of system operators from other activities and the exclusions from the unbundling principle;
- ◆ functions of transmission system operators.

4.2.4.1 Network unbundling

As seen in 4.2.1, transmission network in Russia is organised in such a way that the high voltage lines and substations form the Unified National Electric Grid (UNEG) and are operated by the Federal Grid Company (FGC). Other networks belong to distribution companies. Ownership unbundling is applied: one person or company (except for suppliers of last resort) is allowed neither to hold any interest both in transmission and generation businesses nor to own both generating and transmission facilities. In the EU (see 4.2.2, 4.2.3), the current European Directive 2003/54/EC requires legal, organisational and decision-making unbundling without obligatory ownership separation. Starting from those principles, the new Directive 2009/72/EC is stricter introducing ownership unbundling as the most preferable approach to transmission networks regulation. Persons and companies are not allowed to exercise control over both transmission and generating activities. Ownership unbundling for distribution systems is not proposed.

In Russia any person or undertaking can build new network facilities. If the constructed line meets certain criteria, the owner shall transfer the line operation rights to the Federal Grid Company. Generators are not allowed to construct and own lines, and consumers are allowed to do that only if the line is used for their own needs only. In fact, there is a possibility for direct lines between a power plant and a consumer if the line

- ◆ belongs to the consumer,
- ◆ is at 110 kV voltage level or lower (or at 220 kV with less than 125 MVA of connected capacity),
- ◆ delivers electricity to this consumer only.

However, the direct line regime is not specified by legislation which makes opting for direct lines quite risky.

The current EU Directive does not restrain the possibility of generators and consumers to build and own lines. Although the new EU Directive states ownership unbundling as the preferable regulatory approach, it still gives MS another possibility to apply, the Independent System Operator/Independent Transmission Operator scheme. In addition to the common “unbundling + third party access” approach, the EU legislation specifies explicitly two exceptions:

- ◆ scheme of direct lines between producers and consumers
- ◆ exemption from regulated third party access for a predetermined period.

These two exceptions are to be widely applied in the future. Thus, the EU electricity legislation provides system users with more possibilities to optimise costs of electricity supply and to restrict market power of regulated network monopolies.

It is important to mention that the decision whether to apply the direct line regime or not is left to the MS. As for the temporary exclusion from the third party access, it is proposed that the new supernational Agency (ACER) applies it to lines connecting two or more countries.

In Russia there are also some exceptions to the ownership unbundling principle: one company can control both generation and transmission if it stands as a supplier of last resort. Thus, a kind of discrimination is legalized – the companies which stand as suppliers of last resort have certain privileges in comparison to the other suppliers. Also, the unbundling principle is not applied to isolated systems where competition is considered as limited. In the EU, such a discriminatory approach is not acceptable: discrimination is allowed in favour of green energy only. Although

the EU legislation allows MS to appoint suppliers of last resort, they are provided with no special charters.

One more regulatory difference is important. Russian electricity legislation requires that more than 75% of stocks of the Federal Grid Company belong to the state. It makes completely impossible for market participants to balance the monopolistic power of the state when grid development decisions are made. EU legislation does not require MS to exercise such an all-out control over transmission systems. Neither the current nor the new Directive requires MS to have a certain interest in transmission business. Common regulatory elements (legislative provisions and power of regulators) are considered as sufficient.

4.2.4.2 *Legal features of system operators*

The System Operator (SO) in Russia is an open joint-stock company with 100% of stocks belonging to the state. It is not allowed to combine the dispatching control activity with electricity production and buying/selling with some exceptions. Thus, the SO can buy electricity to ensure parallel work with foreign power systems and system users can exercise dispatching control for their own needs.

TSOs in EU can be of any legal form, but shall be independent in terms of its legal form, organisation and decision making. Ownership and affiliating restrictions and the governmental share are not fixed. To comply with the new Directive, vertically integrated companies in the EU will have either to sell their system operating departments or to transfer operation of transmission facilities to an Independent System Operator/Independent Transmission Operator.

A DSO can be part of a vertically integrated undertaking. Obligatory ownership unbundling and transfer of operation to an independent system operator are not required.

4.2.4.3 *System operator functions*

Functions of the Russian SO are to:

- ◆ ensure the reliability of the system functioning and the quality of electric power, adjust the current frequency, ensure the functioning of the automatic frequency and power control equipment, and of the system related and emergency control equipment;
- ◆ control technological operation modes of electric facilities, develop optimized daily schedules for electric power plants and grids, organize and control the parallel operation modes with foreign EPSs;
- ◆ contribute to forecasting the volume of generation and consumption, participate in forming a reserve of generating capacities, coordinate shutting down and putting into service of grid and generating facilities, participate in developing technological requirements for connection to transmission and distribution grids;
- ◆ issue dispatch commands and instructions to perform the system operator's functions.

TSOs in the EU are responsible for:

- ◆ ensuring long-term ability of the system to meet reasonable demands for transmission of electricity, contributing to security of supply through adequate transmission capacity and system reliability;
- ◆ managing energy flows through the system, taking into account exchanges with other interconnected systems, ensuring a secure, reliable and efficient electricity system and availability of all necessary ancillary services;

- ◆ providing the operators of other interconnected systems with sufficient information to ensure secure and efficient operation, coordinated development and interoperability of the system;
- ◆ ensuring non-discrimination between system users, providing them with the information they need for efficient access to the system.

Thus it is obvious that the functions of Russian and European operators are similar. Common responsibilities are dispatching control (including reserves, ancillary services and so on), contributing to network development, ensuring parallel functioning with other interconnected systems. A specific function of European TSOs, which is not directly specified for the Russian SO, is ensuring non-discrimination of system users.

4.2.5 Conclusions

1. Regulation of electric power industry in Russia and the EU has many common and different elements. The common elements are: unbundling of networks and system operators from other activities, main functions of system operators, the rule of regulated third party access to networks. Though these elements are applied in different ways. In general, Russian regulation can be characterized as more centralized and stricter, while regulation of EU is more decentralized and flexible, providing alternatives and exceptions even to the most important regulatory elements. The new Directive and the new Regulations will make the EU electricity industry regulation more coordinated, harmonised and efficient due to the creation of a supernational regulator, unification of powers and functions of the national regulators and stricter network unbundling. However, the degree of electricity regulation centralization in the EU will remain less extensive than the one currently existing in Russia.
2. The EU Directives allow different regulatory methods to be applied in different Member States. There are possibilities for Member States to make a choice depending on national specific features: to apply or not to apply a certain regulatory element, to separate ownership or operation of networks (with the first option as the most preferable one), to use authorization or tendering procedure for new facilities, to apply the direct line regime or not.
3. Russian legislation does not specify explicitly the direct line principle, although there is no restriction for consumers to construct their own direct lines. The principle of temporary exemption from third party access, which is considered as positive in EU, is not applied in Russia at all. The share of governmental ownership in transmission and dispatching control in Russia is very high and in the EU is not fixed at all.

4.3 Study of EU and Russian electricity markets

The electricity supply industry much differs from other sectors of the economy. It implies:

- (i) large sunk costs which limit entry possibilities,
- (ii) vertical stages of the electricity supply industry (generation, transmission, distribution and retailing) with different optimal scales,
- (iii) a non-storable good delivered via a network which requires instantaneous physical balance of supply and demand at all nodes.

Liberalisation of such an industry needs the creation of a combination of competitive wholesale and retail electricity markets, and regulated transmission and distribution activities. Successful liberalisation requires a well-organized energy production sector, related transmission and ancillary services provision [41].

Experience from electricity liberalisation around the world has produced a certain consensus over some measures necessary to achieve a well functioning electricity market. Liberalisation generally requires implementation of one or more of the following interrelated steps [42], [43], [44]:

- ◆ restructuring of power companies and of the sector as a whole;
- ◆ introduction of competition in wholesale generation and retail supply;
- ◆ incentive regulation of transmission and distribution networks;
- ◆ establishing of an independent regulator;
- ◆ transition from state property to stock ownership (privatisation).

Restructuring, in general, implies vertical unbundling of generation, transmission, distribution, and supply activities and horizontal splitting of generation and supply. The effective separation of generation and transmission activities is crucial for achieving competition in the wholesale electricity markets [45] in order to prevent anti-competitive behavior by generators in the short run and ensure non-discriminatory network access to the other players in the long-term. It is also important to prevent high levels of market concentration (market power) in the restructured power systems. Failure in doing it can hinder the fair participation of generators in the market, also discouraging new entries. Unbundling can take the form of functional, accounting, legal, or ownership separation, with the last one being the most effective [41]. Similarly, unbundling supply from distribution is important for effective retail competition.

Establishing wholesale and retail electricity markets is essential for liberalisation of the industry. Wholesale market design needs to take account of various technical, economic, and institutional issues associated with pricing, contracts, scheduling, balancing, and network congestion, considering the specific conditions of the sector. In the long run, new entries in generation and supply, as well as interconnections with other systems, can also increase competition in the market. Establishing an initially competitive market structure requires institutional initiative at the highest level (government), and all examples of successful restructuring of the industry illustrate the importance of the initial steps to facilitate competition [46].

Transmission and distribution tariffs constitute a significant share of final electricity prices and are not subject to competition. Efficiency improvements and price reductions require appropriate tariff regulation. Incentive-based regulation of networks can promote efficiency and cost savings in the natural monopoly segments of the sector and should prevent anti-competitive effects such as cross-subsidies. Incentive network regulation is based on actual cost consideration. Appropriate regulation, in particular, implementing regulated third-party access to networks, is important for effective competition. Recognising the importance of this, the current 2003/54/EC Directive [35] required EU MS to establish independent regulatory agencies. The independent regulator has to set clear rules for the wholesale market and to minimize regulatory uncertainty.

The main effect of privatization is that the pursuit of profit by private players is expected to lead to efficiency improvement and cost saving. In several countries power system restructuring has resulted in the sale of public enterprises and/or the entry of new private players. An increase in sector-wide ownership diversity can also facilitate direct competition in the generation and supply activities and yardstick regulation of networks by comparative performance. Privatisation can also provide significant proceeds for the government and reduce its future liabilities. However, privatisation is not a prerequisite for liberalisation. In theory, competition and incentive regulation can be applied to publicly owned enterprises. At the same time, there is

satisfactory evidence that privatisation can deliver significant benefits, especially when combined with effective restructuring, competition, regulation and stock ownership [44].

The financial integration of electricity markets often takes place more rapidly than the physical integration of electric networks. In the absence of proactive regulation and control of Mergers and Acquisitions (M&As), electricity companies show a marked tendency towards increased market concentration [47]. It occurs at both national and international levels, and this may limit the effectiveness of competition.

The electricity market integration in Europe has still not developed to a sufficient extent. Restructuring countries have adopted different market models and these have evolved in stages, reflecting a learning process in which liberalisation is in some cases still ongoing. Market participation and efficiency require sufficient liquidity. Standards in contracts help liquidity and stability and facilitate investment to deliver adequate generation capacity.

The analysis of the current situation and the forthcoming evolution of electricity markets both in the EU Member States and in Russia needs particular attention. The opportunity of establishment of common rules for market cooperation is one of the important aims when considering power system integration.

The following sections focus on an analysis of electricity markets in the EU Member States and in Russia. Different important characteristics of power systems and markets are considered. Among them there are:

- ◆ Role of the State governments in the electricity supply industry;
- ◆ Electricity market regulation;
- ◆ Transmission and distribution system operation;
- ◆ Provision of efficient electricity generation;
- ◆ Competition in the retail markets;
- ◆ Competition and pricing in the wholesale markets.

4.3.1 Electricity markets in the EU Member States

4.3.1.1 Role of the State governments in the electricity supply industry

There is a tendency of convergence between the EU and Russia concerning the role of the State and Government in the energy sector; however, some differences remain.

In the EU, competence over the energy sector is shared between the EU institutions and the Member States. The main EU institutions participating in the EU legislative process are the European Council of Ministers, the European Parliament and the European Commission. The EU sets the rules of the internal electricity market mainly in the form of directives and regulations, proposed by the Commission and issued after the co-decision procedure by the Parliament and the Council. The Commission then ensures that the Member States implement those rules. The Member States translate EU Directives into the national law by passing legislation. They also legislate, independently of the EU, over energy matters not falling under the competence of the EU.

National governments do not generally participate in the management of power companies, although they may own electricity companies just like any other state or private entities. Under the second and third Directives and competition rules of the EU, direct management of companies by the government is restricted by the European Commission monitoring the market-

friendly behaviour of state-owned utilities and companies having market dominant position or special rights. The Commission has the duty and the authority to inflict serious penalties on national governments, if they violate the Directives or the EU competition rules by favouring state-owned companies.

4.3.1.2 Electricity market regulation

The regulators play an important role in ensuring the effective power system operation, and the resulting regulatory models are crucial for the proper functioning of the electricity markets. Adequate regulation has a number of characteristics that can be generally accepted. These include clarity, consistency, transparency, independence, effectiveness and flexibility. These characteristics should be pursued regardless of the regulatory model adopted [48].

In the EU, there is a separation between the government political function and the regulatory function. The latter consists in overseeing and enforcing sector-specific rules. The Directive 2003/54/EC has required that each Member State establishes an electricity market regulator, which should be independent of the interest of the electricity system industry. This is to guarantee regulatory stability and to avoid situations in which the decisions of the regulator are constantly modified.

The current Directive sets out the minimum tasks that must be allocated to a regulatory authority. The key responsibilities are to ensure non-discrimination, effective competition, and the efficient functioning of the market. The regulatory authorities have the power and the duty to set network tariffs or tariff methodologies *ex ante* (i.e. prior to their entry into force). They are responsible for monitoring market rules. They can request network operators to modify network tariffs. Regulators also monitor the allocation of the transmission capacity of cross-border and internal lines in case of congestion.

Regulatory authorities have also additional responsibilities. Among them there are [49]:

- 1) The control of an abuse of a dominant position and anticompetitive practices are normally dealt with under competition law. However, regulatory authorities also have responsibilities to monitor and prevent anticompetitive behaviour, in particular abuse of dominant position. As far as access to network and network charges are concerned they have effective powers to maintain competitive conditions in the market.
- 2) Regulators play an important role in ensuring that the interconnections are used in a non-discriminatory way. In the case of a dispute regarding cross-border supply of electricity, the decision-making regulatory authority is the one which has jurisdiction in respect of the system operator that refuses the use of or access to the system.
- 3) National regulatory authorities have an obligation to cooperate with each other in a transparent manner. For this purpose, after the creation of CEER (Council of European Energy Regulators), an independent advisory group on electricity and gas called ERGEG (European Regulators Group for Electricity and Gas) [50] counting on a closer collaboration between EU MS regulators was established in November 2003.
- 4) Regulatory authorities are also entrusted with the task of approving operational and planning standards of the transmission system operator, including schemes for calculation of the total transfer capacity. They ensure that the rules for cross-border trade, in particular allocation of interconnection capacity, are complied with by all players.

At present the regulatory frameworks and the competencies of the various authorities in the power system industry much differ from country to country [51]. In general, the economics,

energy or industry ministries still occupy a central position in the energy policy. However, the sector regulatory authorities have become central players throughout Europe in ensuring network access and approving network tariffs. Their competencies vary significantly, as their resources and regulatory practices do. A new facet in the regulators' activities is their increased European cooperation: CEER and ERGEG have recently merged to set the newly created ACER (Agency for the Cooperation of Energy Regulators) as envisaged and supported by the EU Commission [36], [39].

In many cases, regulators are making positive and effective contribution to the promotion of transparency and non-discrimination in the markets. In general, the regulators have shown a good record of independence and a relatively fast reaction to the changing environment, particularly in countries where liberalisation has commenced later.

4.3.1.3 *Transmission and distribution system operation*

The transmission system operator has to be independent of the interests of generation, supply and sale of electricity, and is established as an entity legally separated from generation, supply and trading companies. It provides non-discriminatory access to the transmission network (third party access) to all system users (generators, suppliers, traders, customers, etc.), including balancing and other system services.

If network capacity is scarce, the decision about which player should use the capacity is based on objective and market-based criteria (e.g. allocated by auction). The operator applies non-discriminatory, cost-reflective transmission tariffs that take account of the investment needs of the network. The network tariff is non-discriminatory when the use of network capacity with certain system services and parameters is priced in a similar way for all system users. The operator allocates network capacity and manages congestions in a transparent and non-discriminatory way, including capacity of interconnections. The operator makes the network tariffs publicly available, transparent and verifiable.

The independence of the Transmission System Operator (TSO) is one of the key elements of the EU energy policy. Only an independent TSO can guarantee non-discriminatory access to the network and ensure that the conditions of using the network, including network tariffs, are defined in a transparent and non-discriminatory way.

To ensure the independence of the TSO, the EU Directive 2003/54/EC has required the unbundling of TSOs from generation and supply. When TSO is subsidiary or part of a group of companies the second EU Directive has imposed the obligation of accounting unbundling to the TSO. This is to ensure that no cross-subsidies take place and tariffs are cost reflective; separate accounts must always be kept for transmission activities. The new Directive 2009/72/EC has recently imposed stricter unbundling obligations to TSOs, having to choose between assets ownership unbundling (preferred option) and the creation of an Independent System Operator/Independent Transmission Operator as responsible for the operation of transmission system.

According to the EU Directives, TSOs shall ensure that the access and the conditions of using the network infrastructure, including interconnections, are objective, transparent and non-discriminatory. The Member States are required to implement a system of third party access to the transmission network based on the published tariffs applicable to all eligible customers.

The revenues of TSO collected via the published tariffs should be cost-based and include an adequate return to cover investments and the capital needed for the maintenance and the development of the whole network infrastructure.

The transmission system operator is responsible for managing internal and cross-border network flows. In the case of interconnections, the TSO manages capacity allocation jointly with those involved TSOs of the respective interconnected systems. The allocation of network and interconnection capacity should be transparent, non-discriminatory and market-based.

Congestion management of internal networks, as well as of cross-border lines, should be market-based and depend on the value of electricity to be transported. Congestion management mechanisms should avoid arbitrary decisions based on non-economic considerations favoring affiliated companies.

The Distribution System Operator (DSO) provides the transport of electricity from the transmission system to the end consumers in its area. Distribution business is a natural monopoly, and therefore it should be separated from the competitive business. DSO is under the control of the Regulator, which approves distribution tariffs. The principle of non-discrimination applies especially to the network tariffs and procurement of auxiliary services.

The independence of the DSO is – as for the TSO – one of the key elements of the EU internal electricity market. Only an independent DSO can guarantee non-discriminatory access to the distribution network and ensure that the conditions of using the network are defined in a transparent and non-discriminatory way.

A possibility exists for the EU Member States to exempt small distributors, with fewer than 100 000 customers, from the management and legal unbundling requirements of the Directives, but not from the accounting requirements. The reason for this is that in small distribution companies the economies of scale may not exist to justify the creation of separate subsidiaries to carry out different functions of a vertically integrated company. The exemption is however not valid for a company that controls several small network companies, which in total serve more than 100 000 customers.

The EU Directives specify the following special duties for DSOs [38], [49]:

- ◆ A Member State may require DSO, when dispatching generation installations, to give priority to power generated using renewable energy sources or waste or combined heat and power (CHP) producers.
- ◆ When planning the development of the distribution network, energy efficiency and/or demand side management measures and/or distributed generation that might supplant the need to upgrade or replace capacity shall be considered.
- ◆ Member States have the possibility to impose certain Public Service Obligations on the electricity undertakings. The specific Public Service Obligation of DSO is to connect customers to their grid under the conditions set by the regulator.

4.3.1.4 Provision of efficient electricity generation

Generation is a competitive activity. Generating companies do not have monopoly rights and compete with each other to provide electricity to customers. They sell their products at prices that result from the supply-demand equilibrium in the market. They are structured as entities functionally and legally independent of transmission and distribution companies, which maintain natural monopoly rights in the electricity market.

Generating companies can be in any type of full or mixed public/ private ownership. Generating companies in the market should not benefit from any advantage such as state guarantees and subsidies or some specific rights. The generating companies make their investment decisions according to their own forecast of the revenues they will get from their activities in the market. If they fail to reach their profitability target, generating companies can go bankrupt.

The generation function can be associated with other activities in the market such as energy supply and trading, ancillary services (such as reactive power supply, frequency control, black start capabilities, spinning reserve and capacity market), fuel purchases, emission certificates, etc.

It is one of the very first requirements of the EU Directives on electricity market liberalisation that full competition at the generation level is enforced in all markets from the very beginning. This requirement was fulfilled by enforcing the following measures [49]:

- ◆ Monopoly rights are eliminated, “de facto” or “de jure”. Generating companies define investment decisions on new generating capacities based on their own view of the economic conditions of each market. Some companies have been divided into smaller generating companies and divested their property to limit their market power on the marketplace. European authorities have to enforce equal treatment for all companies;
- ◆ Customer choice is effective. The second EU Directive has required that all EU generating companies be able to compete in the whole EU since July 1st, 2007, with all customers being contestable. Today most of the markets are fully open;
- ◆ All EU companies are actually separated from government and regulatory functions;
- ◆ No EU company is allowed to benefit from special treatment or state advantage in a discriminatory way;
- ◆ All generating companies are functionally and legally separated from network companies;
- ◆ The revenues of generating companies are market-based, either through bilateral contracts with customers or through the participation in wholesale markets in which several generating companies or importing companies compete to sell their electricity.

Future investments in generation will be based on market conditions. Market participants have indicated that the revenues from the market should be sufficient to cover and attract investments. The use of specific investment-related market mechanisms such as capacity markets and/or capacity auctioning processes associated to longer term contracts for capacities is envisaged.

4.3.1.5 *Competition in the retail markets*

Suppliers and end customers participate in the retail market. Supplier may produce electricity at own power plants or it may buy electricity from the wholesale market. The customers generally are household consumers, small and medium sized industries, commercial and public entities, etc.

Supply is a competitive activity. Supply companies do not have monopoly rights and compete with each other to provide electricity to end customers. They sell their products at prices that result from the offer-demand equilibrium in the market. They offer different electricity products and compete on the level and quality of services they provide. Suppliers are structured as entities functionally and legally independent of transmission and distribution companies, which maintain natural monopoly rights in the electricity market, but may be coupled with producer function.

Supply companies can be in any type of full or mixed public/ private ownership. They should not benefit from any advantage (state subsidies etc.) in the market. Supply companies may go bankrupt, if they are unable to reach the targeted level of profitability.

Electricity supply prices are set by the market for all categories of end consumers. Concerning how prices or tariffs are established, generation and supply prices are set in the market and may also depend on the agreement between the buyer and seller. Network tariffs are regulated, i.e. set or controlled by the regulator. Electricity price paid by end customer often contains tax element. Taxes are decided by the national parliaments.

4.3.1.6 *Competition and pricing in the wholesale markets*

Trade in electricity is either based on bilateral contracts or on electricity exchanges. A specific version of bilateral trade is transacted through brokerage companies, which trade through standardized and tailor-made contracts in a non-centralized way. Brokerage trade is part of the liquid wholesale market, but is not qualified as an exchange trade.

The biggest share of electricity is traded through bilateral contracts. Exchange-based trade generally complements bilateral transactions. Hence, the annual volume of exchange trade is only part of the electricity traded on the basis of bilateral contracts. This percentage is the highest in the Nordic market, where it amounted to 31% of physical electricity trade in 2003. In Germany and the UK this percentage is around 5-10%. Other examples are the power exchanges in France and Austria which have a share of 2-3% of their national power demand [49].

To date, power exchanges exist in almost all EU countries, and the trend is towards the development of regional markets. The organization, level of developments and concrete functions differ from one power exchange to another. The most developed power exchange in Europe is currently NordPool Group which is the common electricity exchange of the Scandinavian countries [52].

Power exchanges are publicly or privately owned, or are in a mixed ownership. The Amsterdam Power Exchange (APEX) is e.g. 100% owned by the Dutch TSO, TenneT, which is fully state-owned. NordPool Group is owned by the Nordic TSOs: Statnett (Norway), Svenska Kraftnat (Sweden), Fingrid (Finland), Energinet.dk (Denmark). OMEL, the Iberian power exchange, is currently owned by 20 shareholders including banks and a group of energy companies, mostly from Spain.

The question of ownership is not relevant from the viewpoint of market rules and organisation. Exchanges are organised as service companies. An example can be again NordPool which is organised in as parent company NordPool ASA with four subsidiaries: NordPool Spot AS (spot market), NordPool Financial Market, NordPool Clearing AS (clearing house) and NordPool Consulting AS. The latter three subsidiaries are fully owned by the parent company NordPool ASA.

Since demand and supply vary continuously and electricity can not be kept in stock, it is necessary to coordinate the dispatch of generating units to meet the expected demand of the system across the transmission grid. This service of generation dispatching is generally provided by the TSO. In general the TSO and the dispatching center are not separated.

Different methods of dispatching are used in the EU countries. In a decentralised dispatching system, as e.g. in the Nordic market, generators are responsible for their own dispatching. The TSO is responsible for the overall balance of the system and coordination. Each one of the TSOs

is responsible for the physical balance in the system and in this respect they have advanced control centers in cooperation with the spot market operated by NordPool (owned by those TSOs). Other countries use balancing groups; some other countries still use centralised dispatching. For system security reasons, the final decision in any case remains with the TSO. Dispatching is a highly regulated activity, often under specific dispatching codes or regulations.

Operation of the transmission grid and the ownership of the transmission grid can be separated. In these cases the ISO (Independent System Operator) operates the transmission system, while the TSO remains the owner of the assets. This approach has been recently relaunched in Europe for allowing a more effective transmission unbundling after the issue of the new EU Directive 2009/72/EC [38]. German TSOs RWE Transportnetz Strom and E.ON Netz have been recently following this path creating the respective ISO, Amprion and Transpower, responsible for the 380 kV and 220 kV networks. Another example is Portugal, where the national transmission grid (RNT) is operated by a public service concessionaire, Rede Eléctrica Nacional, S.A. (REN). Another example was Italy, where until few years ago (Oct. 2005) the state-owned concessionary GRTN operated without owning the transmission network. Nowadays, ownership and operation are in the sole hands of the Italian TSO, Terna. An example of a TSO owning and operating the dispatching centre is ELIA, the Belgian TSO. ELIA is also the 100% owner of the Belgian transmission grid and the interconnectors with the neighboring countries.

4.3.2 Electricity markets in Russia

New legislation regarding the electricity supply industry in Russia was enacted by the national Parliament in 2003. It provides an appropriate base for the industry liberalisation and enforces the competition in the markets.

The final stage of structural reorganization of the Russian electricity supply industry was completed on July 1, 2008 in accordance with RF Government Decree [53]. The reorganization implies creation of the following companies:

- ◆ Federal Grid Company of the Unified Electric System of Russia (FGC UES), comprising transmission network assets all over the territory of the country;
- ◆ Distribution Grid Companies (DGC), responsible for the electric networks at a voltage level of 110 kV and lower in the regions of the country;
- ◆ Six thermal wholesale generation companies (WGCs) and fourteen thermal territorial generation companies (TGCs);
- ◆ Wholesale generation company, responsible for hydro power plants (RusHydro);
- ◆ Energoatom Concern, established in 1992 for centralized state control over nuclear power plants in Russia;
- ◆ System Operator of the Unified Electric System (SO UES), responsible for the provision of system reliability and carrying out the functions of TSO;
- ◆ Council of the Market and Administrator of Trading System. The first one is a non-commercial entity and approves the market rules, enforces existing agreements, allows new market participants, reconciles disputes and claims. The second one is a commercial operator of the wholesale market. It approves bilateral contracts, provides commercial data acquisition, and calculates the spot market prices. Council of the Market and Administrator of Trading System together constitute a Commercial Operator of the wholesale market (CO);
- ◆ Independent Suppliers and Suppliers of Last Resort, established for the retail markets;

- ◆ RAO Eastern Energy Systems, responsible for the far eastern part of the country, which has no conditions yet for the establishment of a competitive market environment;
- ◆ INTER-RAO, established as an import-export provider.

The reorganization of the regulating system in Russia has been carried out in recent years. Transition period in reforming the electricity markets will be over in 2010.

The transformations in the industry undertaken in Russia during the last 15 years fully conform to the liberalization criteria accepted in the EU.

4.3.2.1 *Role of the State governments in the electricity supply industry*

The government in Russia has maintained its traditionally important role in the industry.

The Ministry of Energy and State Agencies are governmental bodies and pursue the following objectives:

- ◆ Development of proposals on the state policy in the energy sector and implementation of this policy jointly with other administrative bodies;
- ◆ State supervision of measures ensuring safe operation of power facilities and efficient use of energy resources;
- ◆ Promotion of legal and economic terms and conditions ensuring efficient and sustainable operation and development of fuel and energy sectors;
- ◆ Promotion of international cooperation in the energy field and ensuring access of electric power companies to the foreign energy resources and markets.

The majority of the aforementioned electric power companies (see 4.3.2) are established as joint stock companies. The Russian Federation has however a significant share of ownership in many of them. The State owns:

- ◆ More than 75% of shares in Federal Grid Company;
- ◆ 100% of shares in System Operator;
- ◆ 100% of shares in Energoatom Concern;
- ◆ More than 50% of shares in WGC RusHydro;
- ◆ More than 52% of shares in the DGCs and RAO Eastern Energy Systems.

Thus, the state government is directly represented in the industry. Thermal wholesale generation companies (WGCs) and territorial generation companies (TGCs) remain to be private. Independent suppliers in the retail markets are private as well.

In general, the existing ownership structure in the Russian electricity supply industry enables to:

- ◆ reduce the share of the State in potentially competitive businesses in the industry;
- ◆ ensure direct participation of the State in the authorized capitals of FGC UES, SO UES and RusHydro at the levels prescribed by the Russian legislation;
- ◆ liquidate the deficit of investments in the development of grid facilities and hydroelectric generation by selling state-owned shares in thermal generation companies.

4.3.2.2 *Electricity market regulation*

The independent regulatory system is created in Russia as a set of State Agencies, Figure 4.2. It has two levels of regulators: federal and local ones. The federal regulators are represented by the Agency for tariff regulation and the Agency for anti-monopoly regulation. The Agency for tariff regulation is responsible for valid tariff setting in the wholesale market. It has the power and the duty to set transmission network tariffs and payments for the SO's services ex ante. The

transmission tariffs are cost-based and comprise operation expenses and those ones for the network development. The Agency approves connection tariffs to the transmission network for new market participants and sets price caps for household consumers in different regions of the country.

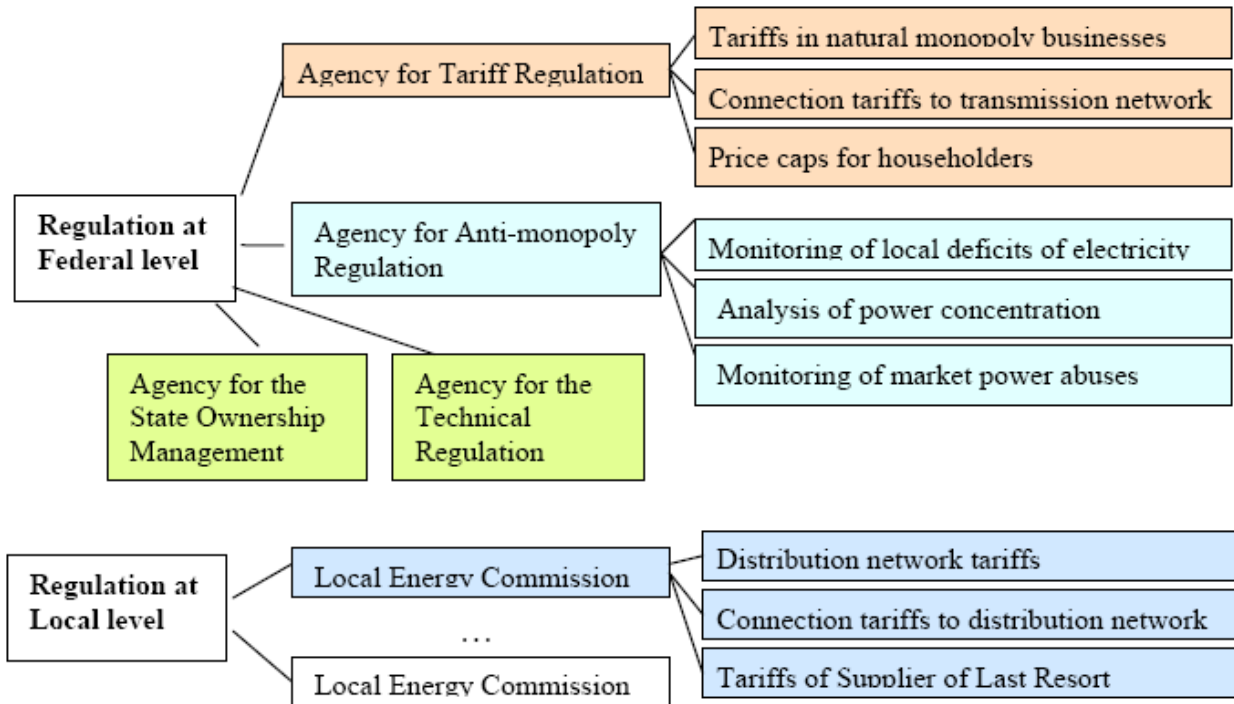


Figure 4.2: Regulation system in the electricity supply industry in Russia

The Agency for anti-monopoly regulation is responsible for effective competition in the wholesale market. It analyses the power concentration in generation and demand, and monitors the market power abuses.

Local regulators set distribution network tariffs and tariffs of the Supplier of Last Resort in the retail markets.

Independence of the regulators is guaranteed as the regulators:

- ◆ do not own or control power companies either directly or indirectly;
- ◆ do not participate in managing any power company;
- ◆ are nominated by the government for a fixed period and their powers cannot be arbitrarily terminated;
- ◆ act within the frame of their responsibility and are accountable for the activities to the government;
- ◆ can be contested in courts for their decisions;
- ◆ are legislatively authorized to develop and approve the regulated tariffs;
- ◆ are authorized to act as dispute-settling bodies between the economic players.

4.3.2.3 Transmission and distribution system operation

Functions of technical operation are divided in Russia between two companies.

Joint stock company System Operator of the Unified Electric System (SO UES) was founded in Russia in 2002. It was the subsidiary of a whole-Russia energy holding RAO “UES of Russia” for several years. Since 2008 it has been a legally independent and separate company. SO UES has six territorial branches and number of local control centers.

The legal and management independence of SO UES from generation, supply and trade is recognized as a key condition for electricity market functioning. The principle of non-discriminatory access to the market infrastructure implies the market participation of all generators, suppliers, traders and consumers having equal rights for conclusion of the contract for electricity delivery. SO UES is responsible for:

- ◆ demand forecasts and electricity balance maintenance;
- ◆ provision of UES’s security and reliability, including maintenance of protective systems, frequency and voltage control, monitoring of technical requirements implementation;
- ◆ provision of standard quality of electricity for end consumers.

The second company involved in transmission network operation is Federal Grid Company of the Unified Electric System of Russia (FGC UES). FGC UES is acting as transmission assets owner. Its responsibilities are:

- ◆ conclusion and realization of the contracts on rendering electricity transmission services;
- ◆ determination of priorities to network access under conditions of limited transmission capacity;
- ◆ revealing information on the available transmission capacity of networks;
- ◆ accounting of network losses and their minimization;
- ◆ provision of the transmission network development.

Currently, export and import are monopoly activities carried out by INTER-RAO on the basis of agreements among States and bilateral contracts between companies.

Energy distribution and generation are unbundled in the retail markets. Distribution is often arranged in the form of regional network companies. The functions of Distribution System Operator are carried out by local control centers affiliated with SO UES.

4.3.2.4 Provision of efficient electricity generation

Generation assets are consolidated into two types of interregional companies: generation companies of the wholesale market (wholesale generation companies – WGCs) and territorial generation companies (TGCs). WGCs are based power plants, specializing mainly in electric power generation. TGCs comprise predominantly combined heat and power plants, which generate both electric and thermal power.

Six out of seven WGCs have been formed on the basis of thermal power plants, one (namely RusHydro WGC) on the basis of hydro generation assets. The configuration of WGCs provides them with roughly equal starting conditions in the competitive market (as far as installed capacity, asset value, and average equipment wear are concerned). Average installed capacity of each WGC is about 9 GW. Thermal WGCs are established according to extraterritorial principles, while TGCs contemplate local stations within neighboring regions. Each WGC comprises power plants, situated in different regions of the Russian Federation, to prevent possible monopoly abuse. Thermal WGCs, while being independent, are the largest wholesale market competitors. They participate in free competition (either mutual or with other generation companies), with the goal to encourage market price formation.

In order to increase transparency and openness of the companies for shareholders and investors as well as to increase liquidity of WGCs shares, WGCs participate in Russian and foreign stock markets by implementing depositary receipts program.

Due to some advantages of major hydro power plants (for instance, their capability of rapid load change and low prices for hydro power), the State limits participation of RusHydro WGC in wholesale market price formation, thus "not interfering" with other market participants. The total installed capacity of RusHydro WGC is about 22 GW.

In order to attract investments to RusHydro WGC as well as to increase both liquidity of RusHydro WGC's shares and the company's value, shares of RusHydro WGC can be traded in Russian and foreign markets.

The wholesale market players also include nuclear power plants (NPPs) consolidated into Energoatom Concern wholly owned by the State. Today Energoatom Concern comprises ten Russian NPPs, with a total capacity of about 23 GW. The Concern is responsible not only for the nuclear and radiation safety of the NPPs, but also for the production and sale of electrical and thermal energy.

In addition to WGCs, Energoatom Concern and TGCs, there are also four independent power producers (IPP) which are generation companies based on the assets of local power companies (Irkutsk, Bashkir, Tatar, Novosibirsk).

Territorial generation companies sell electricity as well as supply regional consumers with heat energy. TGCs are formed according to the following basic principles:

- ◆ establishment of large companies;
- ◆ minimization of possibilities for monopoly abuse;
- ◆ consolidation of power plants on a territorial basis;
- ◆ reduction of state control over electric power generation.

Generating companies are deregulated and involved in competition. Thermal WGCs are independent of the State and of the regulator. All generating companies have full access to the wholesale electricity market under strict competition rules preventing discrimination. Generating companies obtain their revenues through market-based pricing mechanism and take investment decision based on their own projection of their possible future revenues in markets. They can go bankrupt if they fail.

4.3.2.5 *Competition in the retail markets*

Retail market participants are:

- ◆ Electricity consumers;
- ◆ Power suppliers (retailing companies) including Suppliers of Last Resort;
- ◆ Distribution companies and other owners of network facilities that provide distribution services;
- ◆ Electric power producers (not participating/admitted to the wholesale market);
- ◆ Other organizations having the right to sell and buy electricity.

According to the law there are two types of supply companies (retailers) in the retail markets: Independent Suppliers and Suppliers of Last Resort (SLR). Independent Suppliers compete with each other for the end consumers by lowering the price of their services and offering more profitable and convenient conditions for energy supply. They are free to set prices (tariffs) for their services. Independent Supply Companies may choose whether or not to conclude a contract

with a customer. If a buyer and a seller fail to come to an agreement concerning supply terms, the contract is not concluded: the supplier is in fact not obliged to conclude it.

A Supplier of Last Resort (SLR) participates in the wholesale and retail electricity markets and is obliged to conclude a contract with any consumer who applies for it (if this consumer is located within the supplier's area of operation). Regional authorities determine areas of operation of SLR. The status of SLR may be given only as resulting from a competitive tender. The tenders are to be held every 3 years.

The model of retail markets has the following main features:

- ◆ End consumers have the right to choose any supply company from which they are going to buy electricity;
- ◆ Consumers buy electricity from the Independent Supply Companies at free unregulated prices;
- ◆ Unregulated prices are freely set by all suppliers except for Suppliers of Last Resort;
- ◆ Sales mark-up (tariff for services) of Suppliers of Last Resort is regulated;
- ◆ The price offered by Suppliers of Last Resort to end consumers should not exceed unregulated wholesale prices by more than the sum of the sales mark-up and the cost of other regulated services.

The electricity volumes that are within the limits of the “social rate of consumption” are sold to the final consumers at regulated prices.

4.3.2.6 Competition and pricing in the wholesale markets

Upon completion of the electricity sector restructuring (from 2011 onwards), the electricity markets in Russia will have the structure shown in Figure 4.3. There is no market of financial derivatives in Russia yet, but the possibility of opening Power Exchange is under consideration.

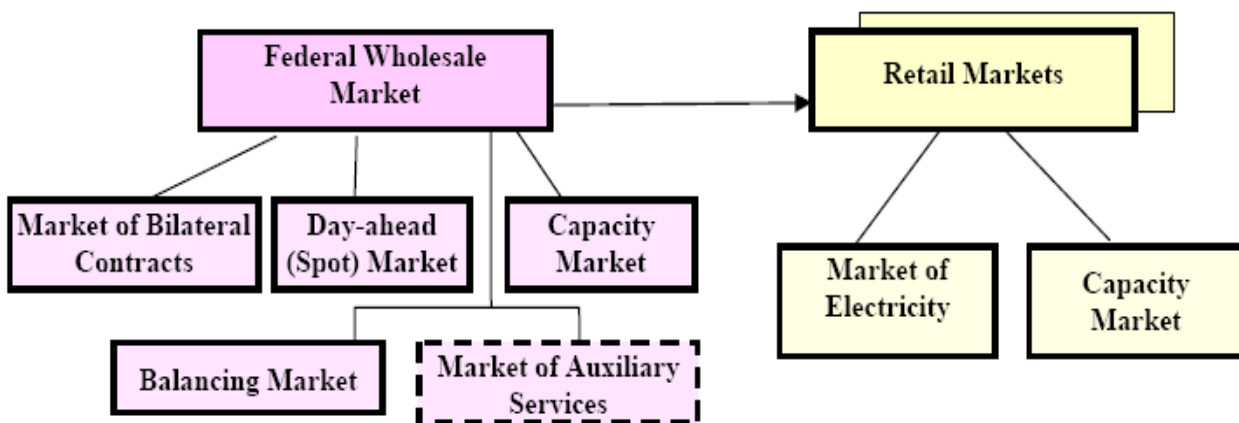


Figure 4.3: Electricity markets in Russia after 2011

The wholesale market is designed as the nationwide market. Because of long distance for electricity transmission, the wholesale market is divided into two large segments – European part of Russia and Siberia. The third part of the country – the Russian Far East – has no conditions yet for competition due to lack of generation and transmission capacities [54].

The power producers in the wholesale market are the 6 WGCs (or WGenCos), the 14 TGCs (or TGenCos), the State-owned concern Energoatom, importers and IPPs, as depicted in Figure 4.4.

Local electricity suppliers (including Suppliers of Last Resort), exporters and large end consumers buy electricity in the wholesale market. Currently, end consumers with connected demand capacity of 20 MVA or higher are allowed to buy electricity in the wholesale market. Producers have the right to enter the wholesale market, if their generation capacity is not less than 25 MW. These limits are supposed to be reduced in the future.

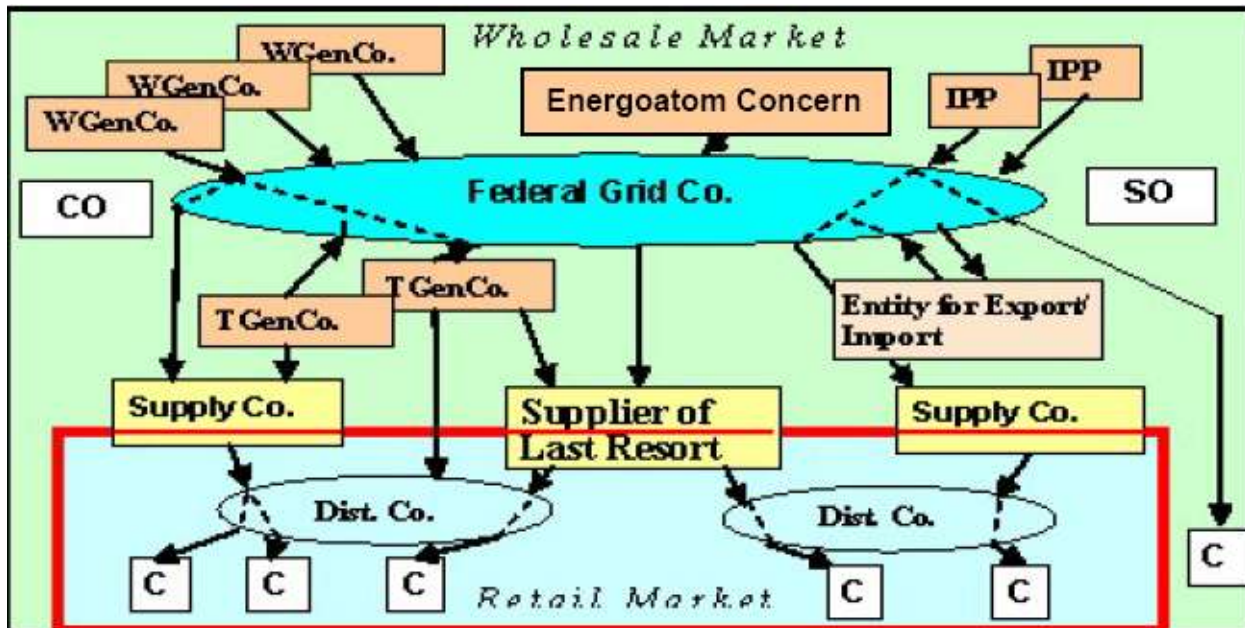


Figure 4.4: Participants in the wholesale and retail markets

Federal Grid Company, System Operator (SO) and Commercial Operator (CO) are responsible for the infrastructures needed for the wholesale market operation. Prices of the infrastructural companies are regulated.

Electricity producers and buyers have two ways of electricity trading. They may participate in the day-ahead (spot) market or arrange forward bilateral contracts for electricity delivery. Bilateral contracts are widely applied in the competitive electricity markets. They stabilize prices and reduce the possibility of market power abuse in the day-ahead (spot) market. The bilateral contracts secure delivery of a certain amount of electricity at agreed prices. They allow producers to choose solvent customers and to use generating facilities in an optimal way.

A balancing market provides equilibrium between generation and consumption within hours. If there are deviations from the day-ahead forecasts, participants in the wholesale market are obliged to sell or buy electricity and capacity in the balancing market. In the day-ahead market participants' bids cover forecasted amounts of power to be produced and consumed. The balancing market, together with the market of auxiliary services, provides efficient operation and optimal level of reliability [55].

The spot market operation needs the development of a modern numerical measurement system. Considering the vast territory of the country, this is a complicated technical problem.

A new pricing mechanism is intended for the spot market. Instead of the single buyer model and average prices, which were used in the 1990s, the day-ahead (spot) market has local marginal

prices. The wholesale customers pay for electricity at the marginal price. It encourages power producers to improve the economic efficiency of production and collect money for development and reconstruction [54].

The retail section of electricity market includes more than 70 regional retail markets. The price of electricity for consumers is calculated proceeding from the terms of bilateral contracts for electricity delivery (purchase and sale of electricity) and fluctuation of electricity prices in the wholesale market.

The electric capacity market was launched on August 1, 2008. Generation capacity is a special commodity as its purchase grants the buyer the right to require availability of generation equipment for production of electric energy at a definite quality in a required amount.

The generation equipment is considered to be available for operation if:

- ◆ System Operator confirms the possibility of utilizing the generation equipment at general primary frequency control and reactive power regulation;
- ◆ System Operator confirms the possibility of using generators of hydropower plants with a capacity of 100 MW or higher at secondary frequency control and automatic regulation of active power flows;
- ◆ Producer ensures operation of generators within the limits of minimum and maximum hourly capacity values set by the System Operator;
- ◆ Producers do not abuse market power in the wholesale market.

For the producers who fail to fulfil their obligations to maintain availability of generation equipment, the capacity price is calculated by the Commercial Operator applying decreasing coefficients.

The markets of electricity and capacity are interrelated. The volume of electricity offered in the producer's bid in the day-ahead market should correspond to the volume of the offered capacity.

From 2012 a long-term capacity market will be organized. Auctions will be held 4 years before the real demand for generation equipment occurs.

Market of Auxiliary Services is not developed enough yet.

4.3.3 Comparison of electricity markets in Russia and in the EU Member States

A general, uniform characterization of electricity markets in the EU Member States presents some issues because the different countries have significant distinctions in the ownership patterns of local power companies, in competencies of the regulating authorities, and in requirements of the national legislations.

Nevertheless, the following common features can be extracted:

- ◆ Competence over energy sector is shared between the EU institutions and institutions of Member States;
- ◆ Governments do not generally participate in the management of power companies;
- ◆ Each country establishes an electricity market regulator, which has to be independent of the interests of the electricity supply industry. National regulators have an obligation to cooperate with each other in a transparent manner;
- ◆ Open access to the national networks and end customers is granted to foreign suppliers complying with EU rules;

- ◆ There is a separation of operators of transmission (TSO) and distribution (DSO) from other power system businesses. The networks operators have to be independent of generation, supply and trading companies;
- ◆ Generation of electricity from renewable energy sources is incentivised and has priority access and delivery;
- ◆ All generating companies are functionally and legally separated from network companies (unbundling). New, stricter regulations will require a ownership unbundling of transmission system or the creation of independent transmission system operator;
- ◆ Technical requirements for systems of measuring and accounting the electricity are standardized;
- ◆ Trade in electricity market is either based on bilateral contracts or on electricity exchanges;
- ◆ Unification of financial requirements for cross-border electricity trade, including transition tariffs, is set;
- ◆ Small customers are involved in the competition in retail markets.

General principles of market design in Russia and in the EU Member States are similar. These common elements are:

- ◆ Unbundling between competitive and monopolistic businesses. Generating companies are separated from network and operating companies;
- ◆ Privatization of companies in generation and supply businesses;
- ◆ Independent regulation of monopolistic businesses;
- ◆ Establishment of an independent system (transmission, distribution) operator;
- ◆ Simultaneous trade through bilateral contracts, day-ahead, balancing and capacity markets;
- ◆ Promotion of the competition in generation and supply businesses.

However, some other elements of electricity markets are different. Russian national legislation has been inspired by world experience of electricity market design, but is not subjected directly to some international directives.

The Russian Federation has significant share of ownership in the infrastructural companies (Federal Grid Company, System Operator, Distribution Companies). Representatives of the Government take part in the management of these companies. The State owns the controlling block of shares of the wholesale generation company RusHydro and fully owns the Energoatom Concern.

Russian legislation does not provide an open access to the national networks and end customers granted to foreign suppliers. This does not allow the penetration of foreign companies to the Russian electricity market.

A significant portion of electricity is generated by hydro power plants using water resources. Other renewable energy sources do not play a significant role in energy balances.

There are no unified technical standards in Russia and EU for systems of measuring and accounting the electricity. Most of technical standards have to be unified in the case of interconnection of electric power grids. Commercial standards including financial requirements and pricing systems must be reviewed in the case of market aggregation. Information unification is vital for compatibility of measurement systems.

Involvement of customers in the competition in retail markets is different in Russia and in the EU Member States. Currently, end consumers with connected demand capacity of 20 MVA or

higher are allowed to buy electricity in the wholesale market. This limit is supposed to be reduced in the future. Regarding competition in the retail market, it is still not developed sufficiently, mainly due to a small number of independent suppliers in the various regions and to the absence of evident benefits proposed by supply companies. Also, only a reduced amount of end consumers are able to change their suppliers.

4.3.4 Possible Scenarios of Market Integration

Interconnection of electric power grids of Russian Federation (RF) and the EU Member States pursues two main targets:

1. Improvement of electricity supply security and reliability in the national power systems;
2. Improvement of economic efficiency of electricity production, transmission and distribution in Russia and the EU Member States through cross-border electricity trade.

Extension of cross-border trade needs an adaptation of market rules, technical standards and market structures. A number of issues depending on the different possible scenarios should be addressed in order to realise a market integration. Possible scenarios are:

Scenario 1. Companies in RF and the EU Member States deliver electricity to one another under bilateral mid- and long-term contracts. Realization of Scenario 1 requires:

- ◆ unification of financial, customs and taxation requirements, and in some cases revision of legislation;
- ◆ standardization of technical characteristics of measurement systems. It concerns the precision parameters of measuring devices, structure and interfaces of databases, data transfer rates;
- ◆ unification of procedures for transmission pricing, including pricing of transit flows;
- ◆ co-ordination of actions between System Operator (SO UES) of Russia and Transmission System Operators (TSO) of EU Member States. It concerns correction of information standards and provision of additional information exchanges;
- ◆ establishment of a legal entity for settlement of claims and conflicts. Such an entity is generally present in any electricity market.

Despite the significant organizational efforts to be made, Scenario 1 can be realistic.

Scenario 2. Russian Companies participate in the day-ahead markets in the EU Member States. Companies of the EU Member States participate in the Russian day-ahead and capacity markets. Realization of Scenario 2 requires fulfillment of all the above measures of Scenario 1. Following additional measures should be also satisfied:

- ◆ revision of the Russian national legislation concerning participation of foreign companies in the domestic markets;
- ◆ standardization of rules for the day-ahead market operation and for balancing mechanisms. It implies unification of bidding procedures, time-schedules of actions, transaction allocations;
- ◆ unification of pricing and billing mechanisms in the day-ahead markets;
- ◆ unification of financial and technical requirements for balancing mechanism;

- ◆ protection of rights of domestic electricity consumers.

Meeting all the requirements necessary for Scenario 2 realization will need huge efforts and costs. Currently, realization of Scenario 2 seems to be unrealistic.

Scenario 3. Creation of a common electricity market in RF and some EU Member States.

Realization of Scenario 3 means that Russian companies and companies of some EU Member States participate in all kinds of a common electricity market, including bilateral contracts, day-ahead and capacity markets, auxiliary services and financial derivative markets.

In addition to the requirements needed for Scenario 1 and Scenario 2, it is necessary also to:

- ◆ standardize auxiliary services;
- ◆ launch the market of financial derivatives in Russia.

Taking into account the conclusions made for Scenario 2 and additional difficulties enumerated there, realization of Scenario 3 seems to be also unrealistic.

4.3.5 Conclusions

1. General conceptions of market design in Russia and in the EU Member States are similar. Common features are:
 - ◆ Unbundling between competitive and monopolistic businesses. Generating companies are separated from network and operating companies;
 - ◆ Privatization of companies in generation and supply businesses;
 - ◆ Independent regulation of natural monopolies;
 - ◆ Establishment of an independent system (transmission, distribution) operator;
 - ◆ Simultaneous trade through bilateral contracts, day-ahead, balancing and capacity markets;
 - ◆ Promotion of competition in the generation and supply businesses.
2. Today's characteristics of the markets present also some differences. The main differences are:
 - ◆ The Russian State holds a significant presence within the ownership of the infrastructural companies. The State owns the controlling block of shares of the generation company RusHydro and fully owns the Energoatom Concern.
 - ◆ The Russian legislation does not provide foreign suppliers with an open access to the national networks and end customers.
 - ◆ There are no unified technical standards in Russia and EU for systems of measuring and accounting the electricity.
 - ◆ Involvement of customers in the competition in retail markets differs between Russia and the EU Member States.
3. The issues to be addressed in the case of electric systems interconnection of Russian and European grids depend on the market integration scenario.
4. Scenario 1 (cross-border trade via bilateral contracts between Russian and EU companies) is the most realistic case, despite the significant organizational efforts needed for its realisation.
5. Scenario 2 (mutual participation of Russian companies in EU markets and viceversa) and Scenario 3 (creation of a joint electricity market for companies of Russia and some EU countries) seem to be both unrealistic for the time being.

4.4 Congestion Management in Electricity Markets

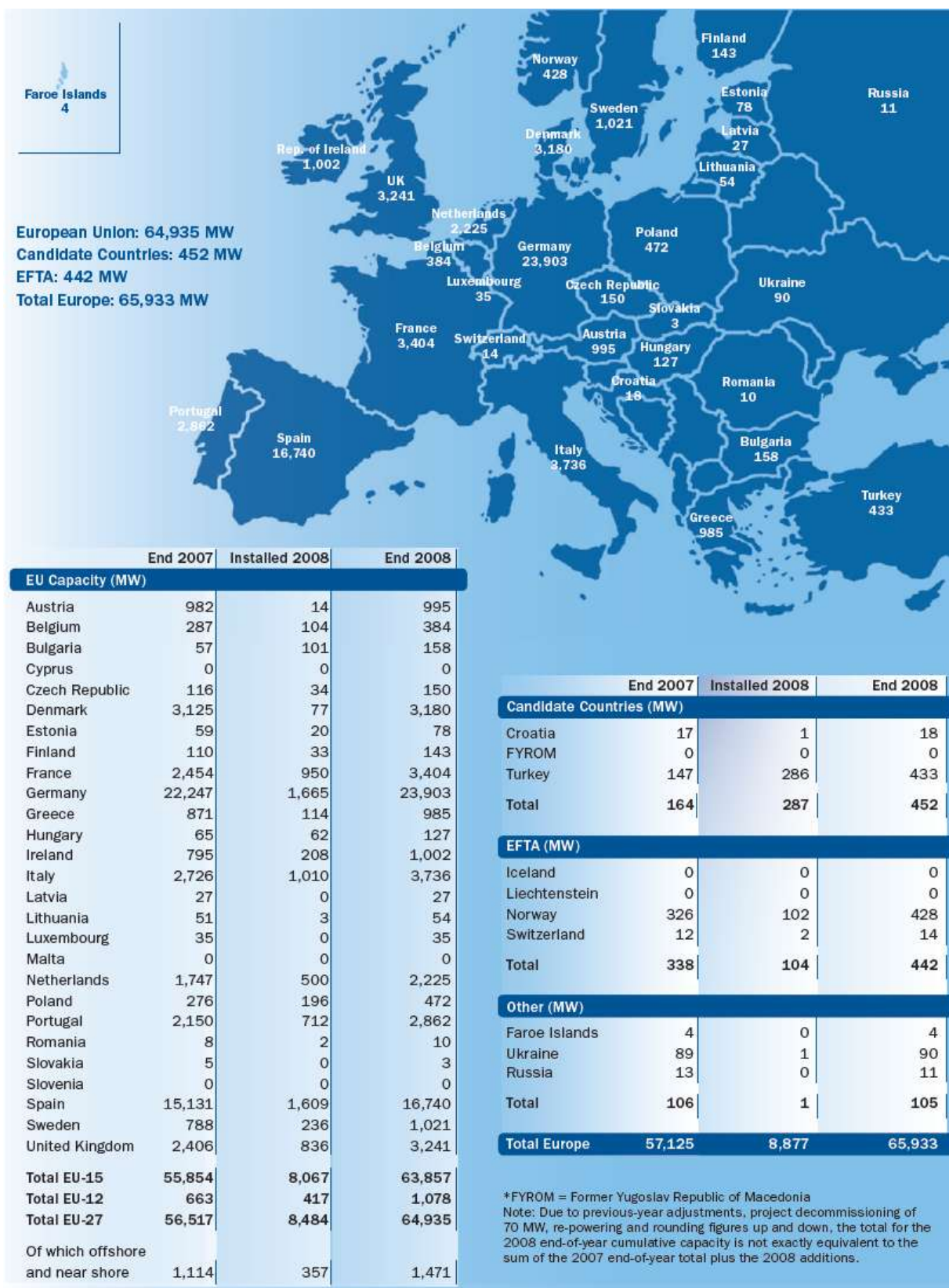
4.4.1 Introduction

In the light of the EU target, by year 2020 around 20% of the total energy will be generated from renewable energy including wind power, conventional power resources such as fossil fuel, nuclear and hydro, will still dominate energy production. With increasing gas and oil prices, it is anticipated that more nuclear power plants (for instance in the UK, France, and Germany) will be constructed to shoulder the base load. The penetration of distributed generation and large scale decentralized generation, in particular wind power with an intermittent nature, is expected to increase significantly and impose extra constraints on the interconnected system. Distributed generation and large scale decentralized generation will not significantly reduce the power transfer requirement, rather, it will require a stronger transmission network and enough reserve from conventional power plants to support the system voltage, balance the generation and demand, and ensure that load centers can be supplied by conventional power when renewable generation is unavailable. It is quite common that large load centers may not always be close to the power generation sources.

Based on national resources available and energy strategies different EU countries have a different mix of energy resources. For instance, in France, there is large-scale nuclear power production, and it is likely that more nuclear power plants will be constructed. In the European electricity market environment, electricity trading will be made across different countries. This will impose further stress to the already constrained interconnected network. The blackout in Italy in 2003 is an example of such a consequence.

Considering the implementation of European Commission target on the promotion of electricity produced from renewable sources in the internal electricity market, it has been noticed that the wind power in Europe has increased from 48 GW in 2006 to 65 GW in 2008 (see Figure 4.5).

As the trend of large scale integration of wind power into electric transmission systems continues, high wind power concentrated at some locations will inevitably need to be transferred to the neighboring transmission systems, subsequently this may cause fast changing power flows on the neighboring transmission systems, which will reduce the system stability margin, the network available transfer capability and the system trading capability. For example, high wind power generation, high power production of conventional power plants in the North of Germany, along with large imported electricity from the Nordic countries, has resulted in large fast changing power flows through the electricity transmission networks of Germany and neighbouring countries such as the Netherlands, Belgium, Poland and Czech Republic. In a very similar situation, large changing power flows are expected to appear across the interface between England and Scotland as some large wind farms will be connected to the British electricity transmission system in Scotland and wind power will be transferred to the load centre of England. It has been recognized that the interface and the interconnected British electricity transmission system need to be enforced in order to fulfil the requirement of large-scale transmission of wind power. There is no doubt that large power flows across inter-connected transmission networks will make the congestion management of the transmission networks very challenging. In the recent studies, it has been found that internal overloads are observed in Germany, Czech Republic, Poland, Belgium and the Netherlands when there are single circuit outages with the high wind power production in northern Europe.



Source: EWEA

Figure 4.5: Wind generation capacity installed in Europe by the end of 2008 [56]

Therefore, power needs to be transferred from the generation sources to the point of consumption through the transmission network. This indicates that even in the situation where distributed generation is increasingly integrated to power grids, in this situation, a strong interconnected transmission network is needed.

4.4.2 Congestion Management in Electricity Markets

Transmission congestion may be defined as the condition where more power is scheduled or flows across transmission lines and transformers than the physical limits of the lines and transformers. The objective of congestion management is to take the actions or control measures in relieving congestion of transmission networks. In principle, congestion management can be considered at different timescales such as: (a) long-term transmission capacity reservation that can be made yearly, monthly, weekly or daily; (b) short-term scheduling of transmission constraints in the day-ahead market; (c) re-dispatching of generation in the real-time balancing market. Depending on market structures and market rules, one or more of these congestion management processes may be applied.

The effective congestion management is crucial to the efficient operation of any electricity markets where there is congestion existing. However, it has been recognized that completely eliminating all transmission congestion is neither necessary nor efficient. In other words, congestion management should compromise between the benefits and costs of solutions. In the short-term, the objective of congestion management is to maintain the physical and operational reliability and security of the electricity transmission network and facilitate a competitive electricity market. Basically congestion management has important impact on spot prices, the degree of competition, and the bidding incentives for energy market participants. In the long-term, congestion management will have impact on the investment decisions of new generators, load, network transmission infra-structure, and the opportunities for integration of alternative generation sources (for instance renewable sources) into electricity transmission networks.

The problem of congestion has increased in recent years, due to a number of reasons:

- ◆ Firstly, deregulation of electricity industry has brought the benefits of possible lower electricity prices and better service quality and large volume electricity trade can be done across-border in competitive electricity markets. However, such electricity trade may cause large-scale transmission of electric power across regions where the unexpected power flows may push electricity networks towards the physical limits.
- ◆ Secondly, in deregulated environments, there is a lack of investment in electricity networks in order to meet the demand and generation where there is a lack of transmission capacity. In other words, transmission capacity, relative to peak load, has been declining in many countries. It is anticipated that this trend under deregulated environments may continue.
- ◆ Thirdly, with the continuous large-scale integration of wind generation into electricity transmission networks, there are difficulties in managing congestion due to fast changing power flows of electricity networks.
- ◆ Fourthly, the continuous internal electricity market development within the member states of EU with increased cross-border electricity trade is making the congestion management an even bigger challenge.

Depending on the market organization and rules, usually the congestion being managed in differs from market to market. In Europe, congestion management methods differentiate between management of congestion inside the control zones of the system operators and that on cross-

border interfaces. In other words, congestion management methods can be classified into the internal and cross-border congestion management methods. Internal congestion – intra-zonal congestion is situated within the control area of a single System Operator’s. Cross-border congestion – inter-zonal congestion is congestion between control areas of system operators where cross-border congestion may not be visible to a large number of market players. It has been recognized that market organization, regulation and investment framework on both sides of the interconnection may be different, and this would make the allocation of cross-border capacity and settlements of congestion costs more difficult and challenging.

4.4.3 The Impact of Congestion

Congested transmission lines indicate that the demand for transmission capacity exceeds the availability. Therefore transmission constraints imply deviation from merit order of power plants to feed the demand, either internally in the control zone of the system operator or across the borders. This loss of wealth results from inability to use the most economical generation resources and is often referred to as the socio-economic cost of congestion (SCC). Relieving transmission constraints reduces the SCC leading to more efficient use of generation resources.

However, there is a theoretical optimal point of congestion where the costs of remedying offset the benefits. Hence it cannot be stated that all congestion is unacceptable and must be alleviated at all costs. Rather, the structural congestion that is always present causing structural issues in accessing cheap generation resources should be dealt with as it will most likely be beneficial. Short-term congestion occurring only occasionally is something else and the choice whether to alleviate it or accept it is quite complex, as the reasons behind do not have to follow from merit order. What is likely to be causing short-term congestion is i.e. maintenance of transmission/generation facilities “weakening” the transmission grid, off-merit order dispatch of generation units caused by strategic behaviour, and last but not least, transmission investment policies of the System Operators related to wind power.

4.4.4 Intra-zonal Congestion Management

Intra-zonal congestion is congestion within a control zone of a particular Transmission System Operator (TSO). It can be detected on a day-ahead basis. Dependent on the market organization and rules, the management of intra-zonal congestion includes (a) either socialized transmission tariffs or uplifting the pool price; (b) or explicitly using Locational Marginal Pricing (LMP).

Besides the power exchange, electricity is traded on the so-called Over the Counter (OTC) market based on bilateral contracts and directly between the buyer and the seller. In a bilateral market, energy is largely traded on a voluntary bilateral basis while dispatch decision is mainly left to the market players and the only requirement is that they need to communicate with the Transmission System Operator in order to check whether the proposed dispatch is feasible in terms of transmission grid operations. In the case of bilateral markets, congestion costs are normally socialized where the utilization of the transmission network needs to be paid as part of transmission tariffs.

For the case of a centralized pool market model, all energy transactions are organized via the market where there is a uniform energy price in the whole control area. In the market, the cheaper generation units have the priority to enter the market while the feasibility of the transactions needs to be examined further. If there is congestion, some out-of-merit generation units are dispatched where financial compensation to the market parties deviating from their planned dispatch schedule.

4.4.5 Cross-border Congestion Management Methods

Cross-border congestion management is to allocate the transfer capacity to market players, who want to trade electricity between control areas. Therefore these methods can also be called capacity allocation methods. The most common methods applied at present are:

- ◆ Pro-rata Rationing
- ◆ Priority based Rules
- ◆ Transfer Capacity Auction
 - Explicit Auction
 - Implicit Auction
- ◆ Market Splitting and Market Coupling

4.4.5.1 *Pro-rata rationing method*

Basically pro-rata rationing method is based on the principle of pro-rata curtailment of transactions. In other words, if demand for capacity exceeds the Available Transfer Capacity (ATC), all transactions are partially curtailed, in proportion to the requested capacity. The deficit of this method provides neither the system users nor the system operator with any incentives for efficient use of the transmission systems. In addition such a method may very likely induce gaming behaviour of the market players. However, the pro-rata method has been considered as a valuable congestion management method in the case of emergency situations where efficiency becomes less important.

4.4.5.2 *Method based on priority-based rules*

The congestion management method based on priority-based rules is that it uses published values of the ATC, and based on some simple mechanism the capacity to the users of the transmission system can be allocated. However, the allocation mechanism depends on how it is implemented. The most common method uses chronological ranking of the reservations until the ATC is completely filled up and subsequent reservations have to be declined, that is the principle of first come first served. The shortcoming of the congestion management based on priority-based rules is that the method does not give any economic incentive to market players. In addition, this method is in favor of long-term trade where contracts always get priority over recent ones.

4.4.5.3 *Method of Transfer Capacity Auction*

For the method of transfer capacity auction, basically market parties bid for transfer capacity where the transmission rights is allocated through the auction. Although there are many variants of the methods of transfer capacity auction, they can be generally classified into explicit auction and implicit auction.

Explicit Transfer Capacity Auction makes a clear distinction between the transfer capacity and energy, of both markets being separated. In the auctioning process, market players bid for transfer capacity that they want to reserve. Those, who are granted capacity, do not necessarily have to use it. Hence the transfer capacity is reserved for the market party who bought it while not minding the energy prices.

Implicit Transfer Capacity Auctioning, on the other hand, combines the transfer capacity and energy markets. The capacity needed for a given energy transaction is implicitly reserved as a function of energy prices. The auction is actually an energy auction, the allocation of transfer capacity being a by-product of a power exchange matching process where bids are submitted

locally with quantity, price and zonal information. Furthermore, the zonal energy exchanges are limited by constraints of power flows on given interconnections not exceeding the allowed transfer capacities.

Both the implicit and explicit auctioning mechanisms could be organized over the single border, or over several borders in a coordinated manner. Due to the fact that the power flows in the meshed interconnected power system are interdependent, it would be better to allocate cross-border capacity in a coordinated manner. Several independent auctions in the same region may become infeasible as transactions could incur unforeseen power flows on the other borders due to the interdependency of power flows in meshed networks.

4.4.5.4 *Market Splitting and Market Coupling*

Using market splitting, a power exchange can ensure the right cross-border power flow by establishing production surpluses in the power exchange's low-price areas, and production deficits in the power exchange's high-price areas. Market splitting is considered to be a congestion management method in the Nordic Pool. Nordic Pool is a voluntary Power Exchange, with one interesting feature: cross-border transfer capacity market can be only accessed by submitting bids and offers to the Power Exchange. It has been found that using the market splitting, cross border transactions can be controlled very well. Market splitting indeed has the same principles as that of the implicit capacity auctioning.

Market coupling can be considered to be a process where a co-operation between two or more power exchanges ensures that during every hour of operation all the available trading capacity is utilized with power flowing towards the high price area. In contrast to market splitting, market coupling is a congestion management method proposed by the European Association of Power Exchanges, namely EuroPEX. In principle, both methods have the same principles as that of the implicit auctioning.

4.4.6 **Financial Transmission Rights – Congestion Hedging Instruments**

In principle congestion should be avoided as it decreases market value, being the sum of producer's and consumer's surpluses, by disallowing cheap, but remote, generation capacity and accessing more expensive local ones. Moreover, due to technical limitations, fluctuations of demand and non-storability, it is very difficult to predict prices, in turn translating into difficulties in making business decisions.

In order to guarantee an acceptable level of price stability, price risk hedging instruments developed, financial products are derived from electricity markets. Although these financial instruments are not congestion management methods, they are complementary to congestion methods. This gives a possibility to hedge against unstable locational prices.

4.4.6.1 *Financial Transmission Rights - FTR*

An FTR gives the holder a right to a share of congestion rents received by the Transmission System Operator if congestion occurs. The allocation of FTRs typically is based on an auction where the benefit of the buyer or seller can be maximized. The auction basically determines the amount of FTRs allocated to market players and market clearing prices. The design of the auction is decided by the Transmission System Operator, depending on the market structure. FTRs are typically long-term instruments and they may have durations from months to years and they can take different forms such as point-to-point FTRs and flowgate FTRs, etc.

4.4.6.2 Contracts for Differences - CfD

Contract for Differences (CfD) is a risk management tool allowing to hedge against differences between a volatile price and certain value. There are different alternatives of CfD available. The CfD could hedge against the difference between two uncertain spot prices (i.e. regional price and a system price), or the difference between the spot price and a pre-defined reference price (or a price profile).

4.4.7 Currently Implemented Congestion Management Methods in Europe

The current implementation of congestion management methods in Europe is shown in Figure 4.6 and Figure 4.7.

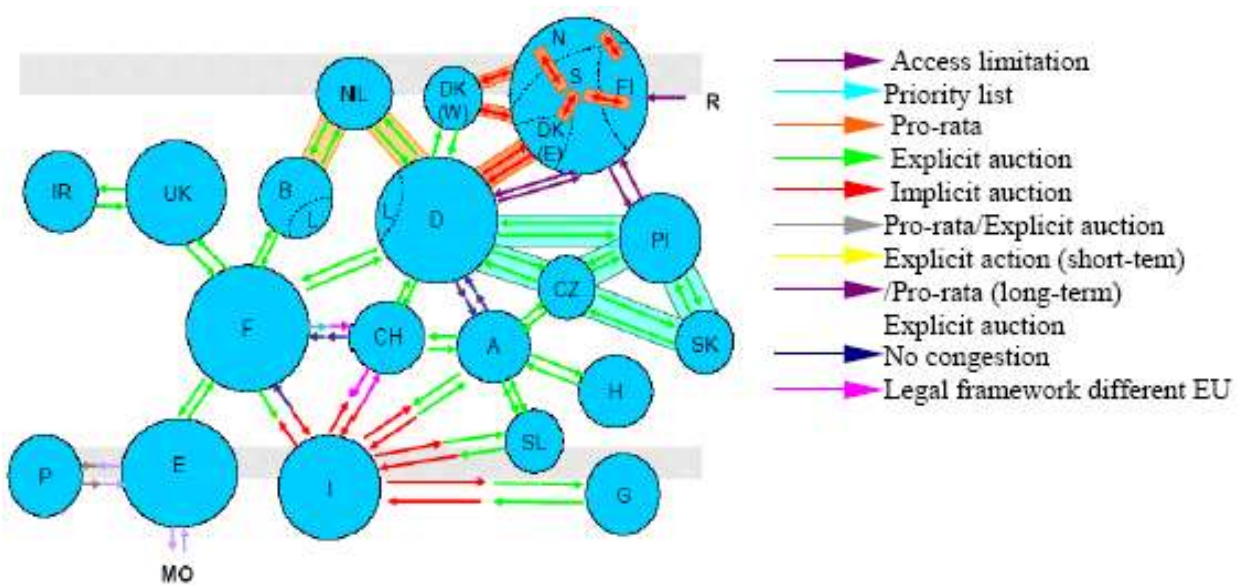


Figure 4.6: Day-ahead capacity allocation [57], [58]

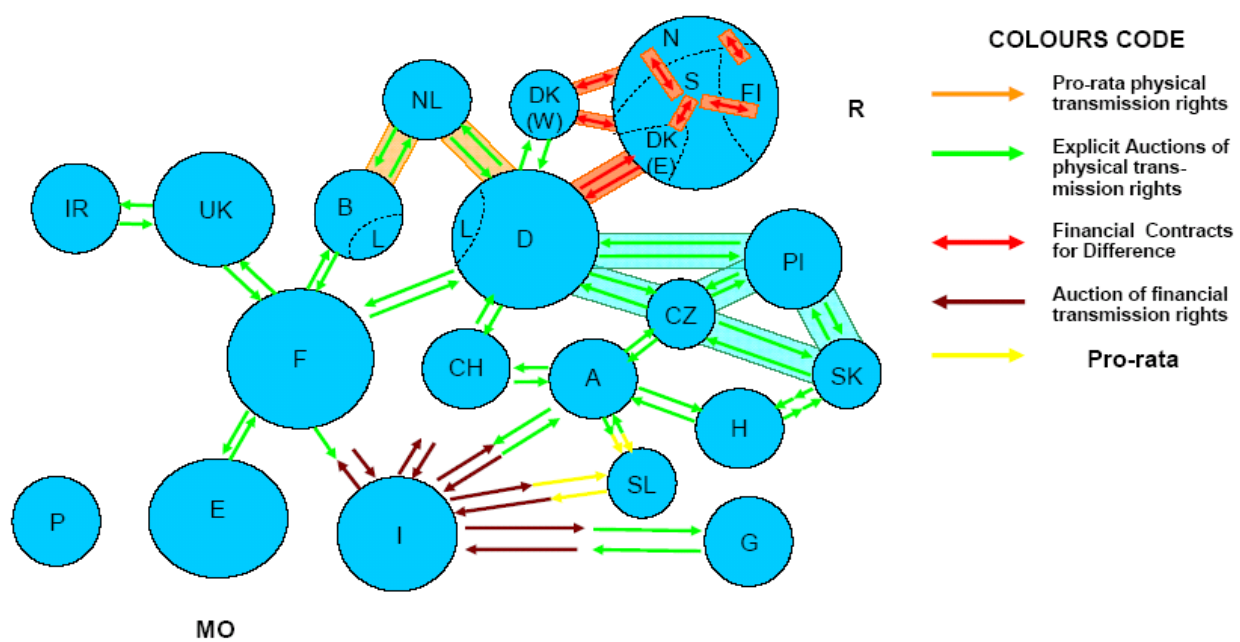


Figure 4.7: Long-term capacity allocation [57], [58]

The allocation of transmission capacity in the day-ahead timeframe is given by Figure 4.6 while the longer term timeframe, i.e. allocation resp. hedging products for month, quarter of an year, year is shown in Figure 4.7.

Two arrows appearing in the same sense of allocation in a certain interconnection mean that, for that interconnection in that allocation sense, there is not a unique capacity allocation method or congestion management mechanism jointly applied by the two TSOs involved. In the figures, underlying transparent rectangles indicate a joint allocation by more than two TSOs, while the rectangles' colours have no relation to the CM method applied.

With the success of the many market integration initiatives, ETSOs are now working towards a more realistic target by seeking to identify an optimal position where the progressive integration of markets at regional and inter-regional levels lead to a seamless mechanism contributing to the IEM. In other words, a Coordinated Model for Regional and Inter-Regional Congestion Management is to be developed and implemented [59], [60].

4.4.8 Congestion Management using FACTS devices

The efficiency of the investment in transmission capacity is very related to the efficiency of utilizing the existing transmission system. In addition, system expansion for congestion management should ensure that the transmission system is flexible enough to meet new and less predictable power supply and demand conditions in competitive electricity markets. In these situations, along with the investment of the transmission network by adding new transmission lines, improving the system operation control capability and maximizing the utilization of transmission assets become very important. Applications of new enabling technologies are able to provide such solutions for electricity companies to maintain the stability and reliability of power systems while handling large volumes of transactions. One example of such enabling technologies is FACTS (Flexible Alternating Current Transmission System) controllers.

The development of FACTS devices has started with the growing capabilities of power electronic components. Devices for high power levels have been made available in converters for high and extra high voltage levels. The overall starting points are network elements influencing the reactive power or the impedance of a part of the power system. Figure 4.8 shows a number of basic devices separated into the conventional control devices and the FACTS devices. All the control devices listed in Figure 4.8 may be used in congestion management depending on the nature of the congestion. However, series control devices are, in principle, more useful where power flow control is of primary objective.

The first column in Figure 4.8 shows the conventional control devices. The second column shows the FACTS-devices using Thyristor valves while the third column shows the FACTS devices using converters.

The third column of FACTS devices contains more advanced technology based on voltage source converter technology such as Insulated Gate Bipolar Transistors (IGBT), Gate Turn Off (GTO) or Insulated Gate Commutated Thyristors (IGCT). It is anticipated that the applications of FACTS controllers will grow in power systems of the future, particularly in the deregulated electricity market environment. The ability of FACTS controllers to support and control power flows across borders of transmission networks is well recognized now. SVC (Static VAR Compensator) and TCSC (Thyristor Controlled Series Capacitor) are the first generation FACTS controllers. The Static Compensator (STATCOM) and the Static Synchronous Series Compensator (SSSC) are two types of the second generation of FACTS controllers that are based

on power electronic switches, while the Unified Power Flow Controller (UPFC) is one type of the third generation, similarly based on power electronic controller. The UPFC has the advantage of controlling both active and reactive power flow simultaneously and independently. The use of FACTS controllers is advantageous as numerous environmental concerns restrict opportunities for network reinforcement through new transmission line construction.

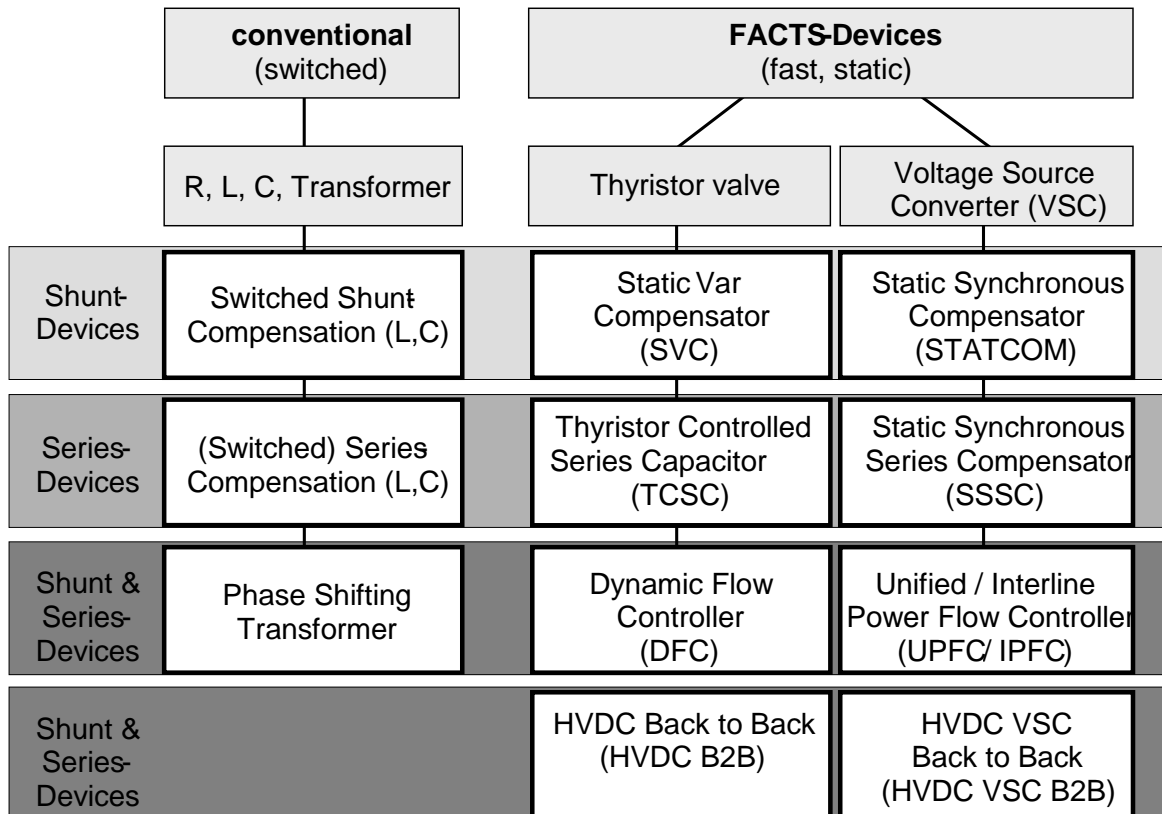


Figure 4.8: Overview of major FACTS devices [61]

In terms of congestion management, phase Shifting Transformers (PST) are perhaps the most common devices in practical use. For instance, PSTs (also called quadrature booster (QB) in the UK) have been used in the National Grid for some years. However, the limitation is the low control speed together with a high mechanical wear of components and frequent maintenance depending on the number of required operations. In the future, as an alternative, with their full and fast controllability, TCSC, SSSC and UPFC may be used in transmission congestion management. In recent years, it has been recognized that VSC HVDC can be used in renewable generation interconnections and power flow and voltage control, hence, congestion management.

Congestion management has become an important issue for TSOs since the deregulation of electricity markets. Efficient congestion management has become more difficult and complex to achieve than in previous decades because of the reality of finite energy resources, the influence of environmental concerns, and policies that prevent the construction of new generating stations and transmission lines together with the constraints of investment costs. However, FACTS technology will be a key technology to open the way towards smart transmission networks,

which should be flexible, reliable, robust and efficient. Better management of existing transmission can help reduce, but certainly not eliminate, the need for new transmission.

4.5 Conclusions

Main advantages and drivers of investments in interconnection of different power systems are the following:

- ◆ promotion of competition and efficiency at both sides of the interconnection;
- ◆ existence and possible reduction of price differences between regions, which could be related to differences in fuel mix and primary resources;
- ◆ increase of system reliability, whose additional gains however normally become progressively less important when interconnections become stronger.

Connecting all participants across the interconnected transmission system makes it feasible to select the cheapest generation; a firm interconnection of different markets promotes increasing of liquidity and competition. It reduces the possibility to abuse market power and it suppresses the higher electricity prices that might have arisen from such abuse.

At the same time there are certain barriers in the way of interconnection:

- ◆ Investment costs can be high for building new interconnections.
- ◆ Energy losses caused by electricity transmission, which depend not only on the length of the interconnection lines themselves, but also on the total distance over which electricity is transmitted.
- ◆ Relatively small cross-border capacities and insufficient allocation of these capacities can lead to congestion within the EU, which could hinder electricity exchange with neighbouring regions.
- ◆ Interconnection capacity competes with domestic generation; therefore interconnection could lead to an increasing import dependency, which may create political resistance.
- ◆ Possible opposition of citizens in the areas where the transmission and interconnection lines have to be built.

Comparative analysis of regulatory issues of ENTSO-E RG CE and IPS/UPS shows the following:

1. Regulation of electric power industry in Russia and the EU has many common and different elements. The common elements are: unbundling of networks and system operators from other activities, main functions of system operators, the rule of regulated third party access to networks. But these elements are applied in different ways. In general, Russian regulation can be characterized as more centralized and strict, while regulation of EU is more decentralized and flexible, providing alternatives and exceptions even to the most important regulatory elements. The new proposal for the EU Directive tends to more centralized and unified regulation but even if the proposal is adopted the centralization and unification degree will be far from the one in Russia.
2. The Directive 2003/54/EC allows a wide range of regulatory methods to be applied in different Member States. There are possibilities for Member States to make a choice depending on national specific features: to apply or not to apply a certain regulatory element, to separate ownership of networks or not, to use authorization or tendering procedure for new facilities, to apply the direct line regime or not.
3. Russian legislation does not specify explicitly the direct line principle, although there is no restriction for consumers to construct their own direct lines. The principle of temporary

exemption from third party access, which is considered as positive in EU, is not applied in Russia at all. The share of governmental ownership in transmission and dispatching control in Russia is very high and in the EU is not fixed at all.

4. Nevertheless, the different regulatory elements applied in Russian and EU electric power systems make no difficulties for the systems interconnection and the powers of the regulatory authorities are sufficient to organise and maintain the parallel work for the benefit of all participants.

General conceptions of market design in Russia and in the EU Member States are similar. The conceptions are based on:

- ◆ unbundling competitive and monopolistic businesses. Generating companies are separated from network and operating companies;
- ◆ privatization of companies in generation and supply businesses;
- ◆ independent (of the industry) regulation of natural monopolies;
- ◆ establishment of an independent System (Transmission, Distribution) Operator;
- ◆ simultaneous trade through bilateral contracts, day-ahead, balancing and capacity markets;
- ◆ promotion of competition in the generation and supply businesses.

Today's characteristics of the markets have differences. The main differences are:

- ◆ The Russian Federation has significant ownership in the infrastructural companies. The State owns the controlling block of shares of the generation company RusHydro and fully owns the Energoatom concern.
- ◆ The Russian legislation does not proclaim an open access for foreign suppliers to the national networks and end customers.
- ◆ There are no unified technical standards in Russia and EU for protective systems, automatic frequency and power flow control, and measurement systems.
- ◆ Involvement of customers in the competition in retail markets is different in Russia and in the EU member states.

The problems to solve in the case of electric systems interconnection depend on the market integration scenario.

4.6 Recommendations

In order to create a joint market platform between EU and Russian systems, it is fundamental that both systems adopt consistent market and technical rules.

It could be recommended to complete the current process towards unbundling of TSOs, particularly including ownership independence from major electricity companies.

The lack of a stable and coherent legal and regulatory framework for interconnections hampers the high investments that TSO have to undertake as asset costs. Regulation should be more stable, predictable and harmonized; authorization procedures should be faster and more efficient.

“Merchant corridors” could be a feasible alternative option to “regulated electricity corridors”; indeed the last ones have impact on national tariffs and therefore hamper the development of highly expensive projects (e.g. HVDC links). The merchant approach needs correct price signals that could be achieved by long-term contracting and instruments for international economic agreements. Long-term contracts have to include competitive elements in order to not affect the competition in the wholesale market. Regulators should provide guidelines on exemption from

third party access, in compliance with the new regulation 714/2009/EC¹⁶, to potential merchant developers and, with the support of TSOs if needed, ensure their compliance.

Policy-makers and regulators should improve investment conditions by avoiding market distortions (e.g. market concentration) and implementing reliable market-based mechanism for allocation of cross-border capacity.

An increased coordination of national TSOs is necessary to improve transparency and feasibility for both regulated and merchant interconnection projects. The creation of ENTSO-E is expected to improve coordination in the European systems.

Synchronous interconnection between ENTSO-E RG CE and IPS/UPS systems seems to be viable but should be considered as a long-term option due to its complexity concerning not only system security and overall reliability but also its operability in electricity market. Asynchronous interconnection should be taken into account in order to achieve a mid-term solution for a joint system/market. However, considering the higher investments needed for an asynchronous interconnection, it is essential to quantitatively assess the benefits deriving from such project.

Investments in the transmission grids of both areas (ENTSO-E RG CE & IPS/UPS) have to be thought over to remove internal bottlenecks that could limit the potential power exchanges across interface lines.

Among possible benefits deriving from investments in transmission (HVAC, HVDC, FACTS), enhancement of power oscillations that could affect the large interconnected power system have to be considered.

¹⁶ REGULATION (EC) No 714/2009 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity (Repealing 1228/2003/EC).

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